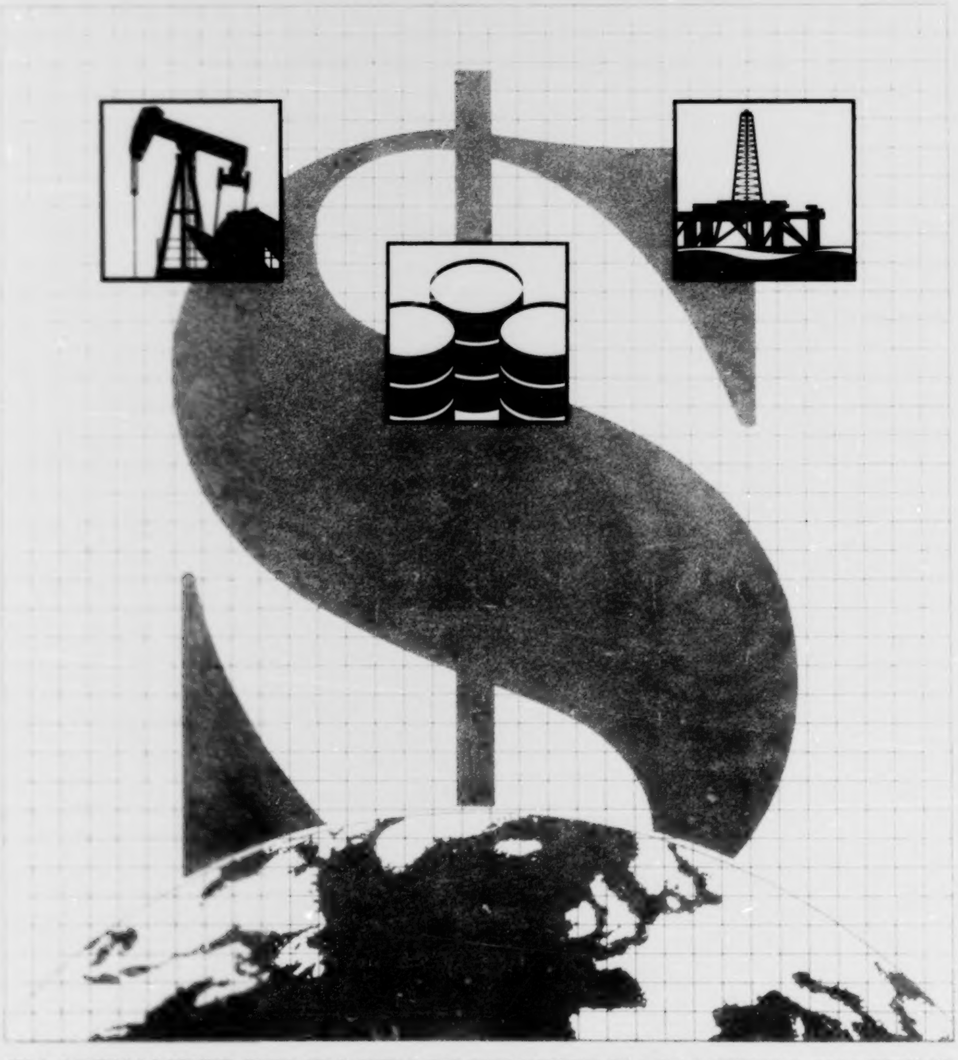

BY **ALEXANDER KEMP** WITH POSTSCRIPT BY CAMPBELL WATKINS

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Petroleum Rent Collection around the World

Petroleum Rent Collection around the World

by
Alexander Kemp

with Postscript by
Campbell Watkins

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Foreword

In the deepest gloom of the National Energy Program someone in the Calgary oil patch was overheard grumbling that "economic rent is a concept invented by governments to justify their grabbing revenues" from resource production. Despite this rather jaundiced view, students of economics are routinely taught that after the available revenues from natural resources (or any resource fixed in supply) have been disbursed to pay the costs of exploration and production – including a return on investment, or "normal profit," equivalent to what could be earned in the next best use of the capital – potentially a surplus remains, called *rent*. This surplus is understood to signal that total revenues are greater than strictly necessary to satisfy all of the various expenditure and incentive needs, or put another way, greater than strictly necessary to provide adequate earnings of all the different types (wages and salaries, interest, requisite return to capital, etc.) that comprise the production process.

The abstract criterion used in this definition to distinguish between what is pure rent and what is not (but rather merely the level of earnings considered "strictly necessary" or "adequate" to maintain factors in their current use or considered "normal") is whether the actual level of return exceeds that which could be earned in the next best alternative use or employment. (Allowance is made for variations in the essential supply cost that, for example, may be due to different conditions of risk and uncertainty.) This pure economic rent is thought to be an unearned surplus, a windfall, that could be collected by taxation (or other means) with neutral impact, causing no (dis)incentive effects on resource development.

It is sometimes assumed that most such rent accrues in the first instance as a residual profit or surplus to the firm. In fact, however, some part of pure economic rent can be collected by consumers if the product price is set lower than would have to be paid otherwise, or by labour if wages and salaries are higher than strictly necessary to attract the required skills and numbers of workers, and by suppliers of raw materials if the returns for one use are markedly greater than another, and so on. The actual amount of pure economic rent is very difficult to measure and its distribution equally hard to trace.

The first question governments face in taxing resource extraction is whether to collect some portion of whatever rent exists or to leave it entirely with any other existing beneficiaries; the answer may be shaped more by ideological than by economic considerations. If governments do decide to appropriate a portion of the rent, the question is how much and by what means? Theoretically, governments can collect as their share the entire sum of economic rent and still leave the structure and performance of the industry unchanged. In that event, the challenge they face is to take only the portion of revenues that is pure rent, the true unearned surplus, and not to cut into necessary earnings. The problem is complicated in a dynamic situation where product and factor prices may be changing; what is needed is a method of rent collection that is flexible and self-regulating, efficient in the sense of automatically taking all of the desired share, but only when there is pure rent to be had, and thus neutral in its effect by virtue of not taking more than the available pure surplus.

In this book, commissioned as part of the Institute's Western Resources Program, author Alexander Kemp applies financial models to compare, against these criteria, the collection of economic rent in selected oil-producing jurisdictions around the world. The fiscal regimes for Alberta and the Canada Lands are included as they existed prior to the National Energy Program, under the NEP, and since then. A Postscript on the Canadian policy implications has been written by Campbell Watkins.

Research began in early 1985 and much of the empirical work had been completed by the end of that year. The dramatic fall in oil prices in early 1986 resulted in discretionary changes being made by several governments to the fiscal terms governing oil production. Additional work was done to assess these developments. Thus the present study is an examination of petroleum rent collection from both 1985 and more recent perspectives. However, the latest changes modelled are for February 1987. Therefore, the analyses do not reflect, for example, the Canadian tax reform proposals nor the Senate vote in Australia on the resource rent tax.

This book is a companion to our recently published ***Resource Rents and Public Policy in Western Canada***, edited by Thomas Gunton and John Richards, which excludes petroleum and focusses on six other resource sectors: nickel in Manitoba; potash and uranium in Saskatchewan; forestry in British Columbia; hydro-electricity in Manitoba and British Columbia; and the Pacific salmon fishery.

The Institute wishes to acknowledge financial support for this petroleum rent study from the Government of Canada, the Government of Alberta, Shell Canada Limited, and Petro-Canada. As usual, any views expressed or conclusions reached remain those of the authors alone, and do not necessarily represent the opinion of the sponsors or the members of the Institute.

Rod Dobell
President

November 1987

Avant-propos

Alors qu'on était en plein découragement à propos du Programme d'énergie national (PEN), on a entendu quelqu'un grommeler, dans le milieu pétrolier de Calgary, que "la rente économique était un concept inventé par les gouvernements pour justifier leur mainmise sur les revenus" dérivés de la production des ressources. En dépit de cette opinion plutôt négative, on continue à enseigner aux étudiants en économie que, après le remboursement des coûts d'exploration et de production – y compris le revenu des investissements, ou "profit normal", équivalent à ce qui pourrait être gagné dans le meilleur et le plus proche placement du capital – à partir des revenus provenant des ressources naturelles (ou de tout autre ressource considérée comme matière première), il reste potentiellement un surplus qu'on appelle *rente*. Ce surplus indique que les revenus, dans leur totalité, sont plus grands que ce qui est strictement nécessaire pour satisfaire l'ensemble des divers besoins en dépenses et en stimulants pour les capitaux, ou mieux, qu'ils sont supérieurs à ce qui est strictement nécessaire pour le maintien adéquat de tous les différents facteurs (traitements et salaires, intérêts, rendement attendu du capital, etc.) qui interviennent dans le processus de production.

Le critère abstrait utilisé dans cette définition pour distinguer ce qu'est une rente pure et ce qui ne l'est pas (mais plutôt simplement le niveau de gains considéré comme "strictement nécessaire" ou "adéquat" pour maintenir ces facteurs à leur niveau actuel d'intervention ou à celui considéré comme "normal") consiste à savoir si le niveau véritable de rendement excède ce qui pourrait être gagné dans le meilleur usage ou investissement le plus proche. (Compte est tenu des variations dans les coûts d'approvisionnement essentiels, dues, par exemple, à différentes conditions de risque et d'incertitude.) Cette rente économique pure est considérée comme un surplus non gagné, une aubaine, susceptible d'être perçue sous forme de taxe (ou par tout autre moyen) sans conséquence dans un sens ou dans l'autre, et sans effets négatifs sur le développement des ressources.

Parfois, on pense que cette rente profite avant tout à la firme, à titre de revenu résiduel ou de surplus. Dans les faits, cependant, une partie de la rente économique pure peut revenir aux consommateurs, quand le prix du produit est fixé à un montant inférieur à ce qu'il serait en d'autres circonstances; elle peut aussi bénéficier à la main-d'oeuvre si les traitements et les salaires sont supérieurs au strict minimum qu'il faudrait payer pour attirer les compétences et le nombre de travailleurs nécessaires; elle peut également profiter aux fournisseurs de matières premières s'il y a des disparités dans les revenus pour des utilisations analogues, et ainsi de suite. La valeur exacte de la rente économique pure est difficile à déterminer, de même que sa répartition entre les différents intervenants dans le processus.

La première question à laquelle doivent faire face les gouvernements en matière de taxation de l'extraction des ressources est de savoir s'il est approprié de percevoir un pourcentage de la rente, dans la mesure où elle existe, ou bien s'il est préférable de l'abandonner entièrement aux autres bénéficiaires; la réponse sera davantage fonction de considérations politiques que de considérations économiques. Mais si les gouvernements décident de se réserver une partie de la rente, il s'agira alors de savoir dans quelle proportion et par quels moyens. En théorie, les gouvernements peuvent revendiquer la totalité de la rente économique pure, sans que cela affecte la structure ni le fonctionnement de l'industrie. Dans la réalité, le problème est de ne prélever que cette partie du revenu qui est une rente pure, c'est-à-dire le véritable surplus ne revenant pas aux autres intervenants, et qui peut être perçu sans leur nuire. La question se complique dans une situation en évolution, du fait que les prix du produit et des facteurs peuvent changer; ce dont on a besoin, dans ce cas, c'est d'un système de perception flexible, s'adaptant automatiquement aux changements, efficace dans le sens où il ne prendrait que la part légitime de la rente, quand elle existe, et par conséquent sans effets négatifs, puisque seule la rente pure serait prélevée.

Dans ce livre, commissionné par l'Institut dans le cadre de son programme sur les ressources de l'Ouest, l'auteur, Alexander Kemp, utilise des modèles financiers comme critères pour comparer les méthodes de perception de la rente économique dans un certain nombre de pays producteurs de pétrole. Les régimes fiscaux de l'Alberta et des Terres du Canada sont également pris en considération, tel qu'ils existaient avant et sous le NEP et tel qu'ils ont continué à exister après. Campbell Watkins a ajouté, en post-scriptum, des considérations sur les implications en matière de politique canadienne.

Les recherches ont commencé au début de 1985 et la plus grande partie du travail pratique était terminée à la fin de cette même année. La chute spectaculaire des prix du pétrole, en 1986, ayant amené plusieurs gouvernements à réviser discrétionnairement leur réglementation fiscale en ce domaine, il a fallu procéder à une évaluation complémentaire des nouvelles données. C'est donc sur une étude de la perception des redevances pétrolières en 1985 et après cette date que porte ce livre, sans toutefois aller au-delà de février 1987. Il n'y est donc pas fait mention, par exemple, du projet de réforme fiscale canadien ni du vote du sénat australien relatif à la taxe sur les revenus provenant des ressources naturelles.

Ce volume vient s'ajouter à l'ouvrage que nous avons publié récemment, *Resource Rents and Public Policy in Western Canada* (Revenus de ressources naturelles et politique générale dans l'Ouest canadien), édité par Thomas Gunton et John Richards. Ce dernier livre laissait de côté la question du pétrole pour s'attacher à l'étude de six autres industries primaires : le nickel du Manitoba, la potasse et l'uranium de la Saskatchewan, l'industrie forestière de la Colombie-Britannique, l'hydro-électricité de la Colombie-Britannique et du Manitoba et les pêcheries de saumon du Pacifique.

L'Institut désire remercier ici le gouvernement canadien, le gouvernement de l'Alberta, Shell Canada Limitée et Pétro-Canada de l'aide financière apportée pour la réalisation de cette étude sur la rente pétrolière. Bien entendu, les idées exprimées et les conclusions auxquelles aboutissent les auteurs reflètent strictement leur point de vue et ne représentent pas nécessairement l'opinion des commanditaires ou des membres de l'Institut.

Rod Dobell
Président

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Executive Summary

For many years the collection of economic rents from petroleum exploitation has been a subject of much concern to governments of all countries containing petroleum reserves. The attainment of this objective in an economically efficient manner turns out to be a complex issue. Difficulties exist both in defining and measuring economic rents in practice and in designing a scheme that efficiently collects them to the state. If governments are unable accurately to measure the appropriate base, it is not surprising that fiscal devices introduced do not efficiently perform their allotted task.

In brief, economic rents from petroleum exploitation are the returns accruing to investors over and above those necessary to sustain (1) ongoing production from existing fields, (2) the development of new but discovered fields, and (3) new exploration. Measurement of the rents requires knowledge of the costs of finding, developing, and operating fields; production profiles; oil prices; and investors' discount rates. This is a demanding list of requirements, but if inaccurate measures are employed by governments economic distortions can then arise.

Knowledge of finding costs is at best elusive, requiring knowledge of prospectivity as well as the actual necessary costs. It may not be immediately apparent that impediments are being introduced. The knowledge that investors are making handsome returns on existing investments may influence policy makers to such an extent that they tax away what are in effect the quasi-rents of exploration. These are returns which can be removed in the short term without apparent damage but which are necessary in the long run if a continuing exploration effort is to be sustained.

This study examines the operation of the fiscal and quasi-fiscal arrangements applied to petroleum exploitation in a wide variety of countries in which petroleum exploitation is an important activity. Both advanced industrial countries and developing ones have been selected and two OPEC members – Nigeria and Indonesia – are included. The countries have been selected to encompass a wide range of fiscal devices, although countries where petroleum production has been nationalized are not included in the study. The prime objective has been to concentrate attention on the delicate relationship between private investors and governments.

The wide variety of fiscal devices applied to petroleum exploitation normally – but not always – includes conventional corporate income tax. However, even when the standard income tax does apply there are often special arrangements added on to reflect the special circumstances of the industry. As far as these special arrangements are concerned, different governments have approached the problem essentially in two basic ways. The first involves the use of auctions for the award of licences or leases. The second involves the employment of special taxation measures. A third, hybrid approach can be distinguished in some developing countries: this initially involves bids by investors but is followed up by negotiations between the investor and government, frequently leading to revisions in the initial bids.

Regarding the special taxation arrangements there is a bewildering variety of details across countries, but the instruments developed over the last 15 years can essentially be categorized under five broad headings: (1) royalties and production taxes, (2) specially modified profit-related taxes, (3) modified production-sharing agreements, (4) windfall profits taxes, and (5) resource rent taxes. In some countries more than one of these five instruments is employed, in addition to conventional corporate income tax.

Fiscal devices may be judged by various criteria. The economic distortions that may be produced constitute one obvious criterion. Thus, if exploration, new field developments, or production are impaired by fiscal devices, distortions have clearly been introduced. In the present context fiscal systems can be judged by the accuracy with which they collect the economic rents. The more directly a mechanism is related to the target of economic rents the less likely are distortions. The more closely the fiscal mechanism is related to economic rents the higher can be the level of take without introducing distortions.

A scheme that is regressive in relation to changes in rents is both inequitable and likely to produce economic distortions. Such a scheme would collect a higher share of the rents the lower these rents became either through higher costs or lower oil prices. A system that collected a given proportional share of the rents as oil prices or costs changed would not result in economic distortions and it could be said to be equitable as well.

A progressive system, which collects a higher share of the rents the higher the rents become (either from rising oil prices or lower costs), is also arguably an equitable system. However, it could introduce a different type of economic distortion, namely, an incentive to engage in "gold-plating"-type expenditure.

With the aid of a set of computerized financial models and a suite of model fields, the effects of the fiscal systems in a number of jurisdictions were simulated under oil price perspectives of 1985 and 1986-1987. The simulations were undertaken at two decision times, namely, those relating to new field developments and to exploration. The results were calculated for different discount rates.

A main conclusion of this study is that the great majority of the fiscal systems do not perform very efficiently as collectors of economic rents. In Australia the Resource Rent Tax scheme performs better than many others, though the inclusion of the normal income tax can mean that in principle disincentives could emerge. The very high threshold rate employed also means that significant rents may remain with investors. The other main fiscal system in Australia provides a stark contrast. The performance of the scheme incorporating the conventional royalty and production levy is such that it is highly regressive in its relation to economic rents. There are distinct possibilities of disincentives emerging under conditions of high costs or low oil prices. This system is not at all well related to economic rents in its structure because of the sizeable production-based components.

In the United Kingdom the fiscal system applied to petroleum exploitation is now wholly profit related for new fields. This scheme performs more satisfactorily than many others in the study, often taking a high share of rents when they are large and a much smaller share when they are small. Policy makers have attempted to relate the take to rents. The link is via the modified special profits-related tax. While the scheme works moderately well, it is still inherently insufficiently flexible to cater automatically for the wide range of operating conditions likely to obtain. The reasonable performance has also been brought about at the cost of great complexity. The need for some discretionary modifications will continue as the operating environment changes.

The Norwegian system applied to new fields is also wholly profit related. The average take in this country continues to be very high and the system's flexibility to changes in the operating environment remains modest. The system is related to profits but not to profitability. It is thus not directly linked to economic rents. There is a danger that it does not take sufficient account of differences in unit cost conditions across fields. Given the high level of take, disincentives could still emerge. The limited automatic flexibility probably means that discretionary changes will require to be made as the operating environment changes.

In China the system incorporates a royalty, production-sharing scheme, income tax, and participation. The scheme is regressively linked to economic rents. It is inherently inflexible in response to major changes in the operating environment, particularly those due to big oil price changes. The system produces a comparatively modest level of take on the smaller, low cost fields. If these fields dominate then perhaps no economic distortions will be produced. But the result has been produced by a scheme which is not accurately collecting the rents. A scheme which was more closely related to the rents could perform more efficiently from an economic viewpoint and possibly collect a higher share of the rents.

In Malaysia the system is complex and contains a royalty, production-sharing scheme, and income tax. The level of take is very high and the scheme is regressive in its relationship to economic rents. There is a distinct lack of flexibility in the appropriate directions. In particular, if exploitation were to take place in deeper waters or oil prices were to fall again, economic distortions would readily be produced. The system performs its function effectively only within a narrow range of oil prices and costs. Discretionary changes will have to be made when the operating environment shows significant changes.

In Indonesia there is a production-sharing system with income tax. The system is profit related but not directly linked to economic rents as seen by investors. The level of take is high and there is not much inherent flexibility in the correct directions in response to changes in the operating environment. If exploitation were to take place in deeper waters or oil prices fall again, discretionary changes would have to be made to prevent significant distortions from emerging.

In Egypt there is a production-sharing scheme which is profit related but not directly linked to economic rents as measured by investors. The level of take is high, and the scheme is inherently not very flexible in response to changes in the operating environment. To avoid distortions changes would need to be made to the terms if oil prices or costs change by significant amounts.

In Nigeria the system incorporates a royalty and special profits-related tax. The level of take is very high and the system has not been inherently very flexible to changes in the operating environment. It is not directly linked to economic rents. In response to the recent falls in oil prices, complex rules have been instituted to reduce the effective profits tax to avoid economic distortions. The resulting scheme is more complex but is still not well related to economic rents. Further discretionary changes will be required in response to significant changes in the operating environment.

In Alaska there is a royalty, production tax, state income tax, and federal income tax, as well as a bonus bidding system. The tax components of the whole scheme produce a high level of take and a system which is regressive in its relationship to economic rents. The tax system is not very flexible in response to changes in the operating environment. The very high level of take is sustained by high prospectivity, but, if unit exploitation costs increase significantly or oil prices continue at low levels, discretionary changes in the system may well be required.

In the U.S. Outer Continental Shelf there is a system of bonus bids, royalty, federal income tax, and Windfall Profits Tax. The scheme is regressively related to economic rents. The tax component in the overall take is comparatively low on the most likely field situations and this prevents distortions from emerging. Though the royalty and tax system could introduce disincentives in deepwater circumstances under low oil prices, the extent to which this is likely to happen is less than in other jurisdictions. The efficiency of the whole system depends upon how well the bidding system operates.

In Texas the fiscal system includes local property tax, state production tax, federal income tax, and Windfall Profits Tax. Royalties are generally payable to private landlords. On reasonably profitable fields the tax take is not especially onerous; only on marginal fields would disincentives be produced. The property tax element is well directed at economic rents though the other components are not.

Under the fiscal system in Alberta the provincial royalty is a dominant ingredient. The royalty formula makes royalties payable a function of well production volumes, oil prices, and the time of discovery. There are some elements of progressiveness built into the scheme. The royalty tax credit, royalty rebates, and royalty holidays help to reduce the potential regressiveness of the scheme in present-value terms, as these reliefs are generally available early in a field's life. Combined with front-end reliefs for an ongoing investor the overall system in pre-NEP and post-NEP circumstances becomes one which is only mildly regressive over the most likely cost conditions. Under higher cost conditions the system becomes more noticeably regressive. The royalty formula and the many associated reliefs and allowances have some inherent flexibility in the required direction but are not sufficient to cater automatically for a very wide range of operating circumstances. For these reasons there is likely to be a continuing requirement for discretionary changes in response to major changes in the operating environment.

Under the post-NEP system in Alberta, where royalty holidays are very significant, the tax take is often very moderate on the most likely field situations. The effectiveness of the whole system in collecting economic rents depends on how efficiently the bonus bidding system operates.

A noteworthy feature of the whole scheme applied to Alberta, with its proliferation of deductions and allowances, is its great complexity. The compliance costs are higher as a result. The exploration incentives may well work, but it is arguable that a scheme which was more directly linked to economic rents could meet all the required objectives with less complexity and frequency of discretionary changes.

Under the NEP the fiscal system in Alberta included the PGRT. This was not a crude production tax but it was not related to economic rents. Consequently the overall system was not linked to rents. The system of PIP benefits helped to prevent more serious distortions from emerging. Their introduction is characteristic of the checks and balances which have played a significant role in the petroleum fiscal mechanisms in Canada for some years. As noted above, it can be argued that a more efficient result with lower compliance costs could be achieved by a simpler scheme more directly targeted on economic rents.

In the Canada Lands the PIR on its own generally performed in a reasonably efficient manner. When it was combined with the conventional royalty, economic distortions could be produced in situations where exploitation was not very profitable. When the PGRT was added as well, the chances of economic distortions emerging were significantly increased. The PGRT instrument was not sufficiently sensitive to major changes in the operating environment to prevent disincentives from emerging.

The post-NEP system on the Canada Lands is much more sensitive to changes in the operating environment than the NEP one. The range of conditions that are included in the Canada Lands, however, is very great. There are enormous differences in the field sizes and costs in the different geographic locations. The only significant fiscal device which is differentiated geographically appears to be the investment tax credit. This provides a worthwhile incentive for projects with very high front-end costs and influences the size of the tax take in present-value terms.

The complex system of taxes and allowances results in the post-NEP scheme being regressive in onshore situations, and, where the fields are marginal, disincentives could emerge. As in Alberta, the system of incentives for exploration operates strongly in the post-NEP situation. Canada has stronger exploration incentives than most petroleum-producing countries.

The fiscal systems examined share the risks of petroleum exploitation between investors and governments in ways which essentially depend on the structure of the mechanisms. Systems that are heavily based on production leave the bulk of the risks with investors. Systems that are wholly profit related and that permit new exploration and development costs to be set off against income from other projects entail government acceptance of a much higher share of the risks. Systems that incorporate a large production-based component were often found to be likely to cause economic distortions. The possibility of a trade-off should exist here. A fiscal system that entailed the acceptance of a high share of the risks by the host government should imply that the government should be able to collect a higher share of the economic rents.

The main findings of this study are that the fiscal and quasi-fiscal devices in existence in many petroleum-producing countries do not collect the economic rents from petroleum exploitation in a very efficient manner. The instruments employed are frequently not directly targeted on economic rents. It follows that the rents cannot be efficiently collected. There is likely to be a lack of accuracy and economic distortions may well arise. There is, consequently, a need for discretionary changes. This need is increased if the operating environment is subject to large changes. Fiscal mechanisms that are directly targeted on economic rents will more effectively collect economic rents, reduce the need for discretionary intervention by governments, and improve the investment climate to the advantage of all.

A combination of bonus bids plus a resource rent tax offers the best hope for the accurate collection of economic rents without introducing distortions. The bonus bids can extract *ex ante* rents and provide governments or other resource owners with an early cash flow from the provision of mineral rights to investors. The resource rent tax can collect *ex post* economic rents and provide a cash flow to governments in subsequent years.

The proper design of a resource rent tax raises several complex technical issues. If the threshold rate is not accurately specified the rents will be inaccurately measured, with dangers of either undercollection of rents or disincentives emerging. Governments have a strong preference for stability of revenues over time. This is generally not possible with petroleum exploitation but devices such as advance resource rent payments – sharing with initial production and subsequently creditable against the resource rent tax liabilities – can help to spread the flow of revenues more evenly. The use of the device of advance Petroleum Revenue Tax in the United Kingdom, where the early production-based payments were credited against later Petroleum Revenue Tax, is an example of this type of scheme.

Abrégé

La perception des rentes économiques en provenance de l'exploitation des gisements de pétrole est un problème qui préoccupe depuis longtemps les divers gouvernements des pays possédant des réserves de ce minéral. La mise au point d'une formule adéquate et économiquement efficace est certes complexe. Les difficultés se présentent à la fois au niveau de la définition et de l'évaluation pratique de ces rentes et à celui de la création d'un mode de perception satisfaisant pour l'État. Si les gouvernements se révèlent incapables de déterminer avec précision l'assiette appropriée des rentes, il n'est pas surprenant, dans ces conditions, que les mesures de perception choisies ne répondent pas à leur attente.

En bref, les rentes économiques dérivées de l'exploitation du pétrole sont les revenus qui doivent revenir aux investisseurs outre et par dessus ceux nécessaires (1) au maintien de l'exploitation des gisements en cours, (2) à la mise en service des nouveaux gisements déjà découverts et (3) à la poursuite des explorations. L'évaluation des rentes suppose que soient connus : les coûts d'exploration, de démarrage et d'exploitation des gisements, les courbes de production, les prix du pétrole et les taux d'escompte des investisseurs. Certes, il s'agit d'un ensemble exigeant de conditions préalables, mais le manque de renseignements en ce domaine entraîne des distorsions économiques graves pour les gouvernements.

L'évaluation des coûts d'exploration est, pour le moins, aléatoire; elle fait appel à la prospective aussi bien qu'à une connaissance des coûts réels nécessaires. Les obstacles qui apparaîtront par la suite ne sont pas évidents à première vue. Ainsi, l'idée que les investisseurs réalisent des gains substantiels sur les investissements existants peut influencer les législateurs jusqu'au point qu'ils finiront par taxer, avec des effets désastreux, des revenus qui ne sont, en fait, que les conséquences de l'exploration. A court terme, ces profits peuvent être prélevés sans dommage apparent, mais à long terme ils sont nécessaires si l'effort d'exploration doit se continuer.

Cette étude examine le fonctionnement des mesures fiscales et para-fiscales tel qu'elles sont appliquées à l'exploitation du pétrole dans certains des principaux pays où cette activité est importante. On y étudie des pays industriels avancés, d'autres en voie de développement, ainsi que deux pays membres de l'OPEC, à savoir le Nigéria et l'Indonésie. La sélection a été faite de manière à permettre l'analyse du plus grand nombre possible de formules, bien que les pays où la production pétrolière a été nationalisée aient été écartés. L'objectif principal a été de réfléchir sur le délicat problème des rapports entre les investisseurs privés et les gouvernements.

La grande diversité des mesures fiscales utilisées inclut normalement, mais pas toujours, l'impôt classique sur les revenus des corporations. Cependant, même quand cet impôt existe, d'autres mesures spéciales viennent souvent s'ajouter, qui révèlent les circonstances particulières propres à une industrie donnée. Les gouvernements tendent à adopter, pour régler leurs problèmes respectifs, deux attitudes principales : la première est de recourir aux enchères, pour l'octroi des licences et des baux; la seconde est de faire appel à des impositions spéciales. Il existe aussi une troisième attitude, hybride des deux premières, que l'on retrouve dans quelques pays en voie de développement : au départ, les investisseurs envoient leur soumission, suite à un appel d'offres, et ensuite des négociations ont lieu entre les investisseurs et le gouvernement, pour aboutir souvent à une révision des données initiales.

En ce qui concerne les mesures fiscales particulières, il en existe une variété extraordinaire, mais la pratique des quinze dernières années permet de les répartir essentiellement en cinq grandes catégories : (1) royalties et taxe à la production, (2) taxes aménagées en fonction des gains, (3) accords particuliers de production en collaboration, (4) taxes sur les profits exceptionnels et (5) taxes sur les revenus provenant des ressources. Dans certains pays, outre l'impôt traditionnel sur les revenus des corporations, il existe des mesures fiscales relevant de plus d'une de ces catégories.

Divers critères peuvent être utilisés pour juger les mesures fiscales. Les distorsions économiques qu'elles entraînent en est un. Ainsi, quand l'exploration, le développement des nouvelles découvertes ou la production sont contrariés par l'une de ces mesures, il est évident que des distorsions ont été introduites. Dans cette perspective, les systèmes fiscaux peuvent être évalués en fonction de l'efficacité qu'ils offrent dans la perception des rentes économiques. Plus ils visent à s'adapter à la rente économique, moins les dangers de distorsion sont grands. Plus ils se conforment à cet objectif et plus il est possible de prélever des revenus sans risques économiques majeurs.

Un système qui fonctionne dans le sens opposé à celui des variations dans les revenus sera à la fois inéquitable et facteur de distorsions. Plus un tel système s'approprie une large part des revenus et moins il y a de revenus, soit du fait d'une augmentation dans les coûts, soit à cause d'une chute dans les prix du pétrole. Par contre, un système qui percevrait un pourcentage de revenus proportionnel aux variations dans les prix du pétrole ou dans les coûts ne provoquerait pas de distorsions et pourrait être considéré équitable.

Un système progressif qui perçoit une plus grande part des revenus quand ceux-ci viennent à augmenter (soit du fait d'une hausse dans les prix du pétrole, soit du fait d'une diminution dans les coûts) peut être, d'une certaine manière, considéré comme équitable. Il pourrait cependant provoquer un genre différent de distorsion économique, à savoir, servir de stimulant à des dépenses ostentatoires.

Dans cette étude, les effets des systèmes fiscaux adoptés dans les pays sélectionnés ont été simulés grâce à l'aide d'un ensemble de modèles financiers mis en ordinateur. Une série de secteurs pétroliers types ont été examinés dans la perspective des prix du pétrole de 1985 et de 1986-87. Les simulations ont été effectuées au niveau de deux moments décisionnels caractéristiques : ceux qui concernent le développement des nouveaux gisements et ceux qui ont trait à l'exploration. Les résultats ont été calculés en fonction de différents taux d'escompte.

Une des principales découvertes de cette étude, c'est que les systèmes fiscaux, dans leur grande majorité, ne perçoivent pas les rentes économiques d'une manière très efficace. En Australie, le système de taxation sur les revenus provenant des ressources donne des résultats meilleurs que dans beaucoup d'autres pays, quoique l'inclusion au système de l'impôt normal sur le revenu puisse provoquer des effets anti-stimulants toujours possibles. Le très haut taux minimal adopté veut dire aussi que l'investisseur conserve des revenus importants. L'autre système fiscal en vigueur en Australie contraste vivement avec celui-ci. L'imposition de royalties conventionnelles, combinées avec une taxe à la production, aboutit à des effets très régressifs sur les rentes économiques. Il y a de fortes chances de voir apparaître des effets anti-stimulants en cas de coûts élevés ou de baisse dans les prix du pétrole. Du fait de ces mécanismes principalement basés sur la production, ce système n'est pas du tout en rapport avec les rentes économiques.

Au Royaume-Uni, le système fiscal, en ce qui concerne les nouveaux gisements, est maintenant entièrement établi en rapport avec les profits. Ce mécanisme fonctionne d'une manière beaucoup plus satisfaisante que pour beaucoup d'autres pays analysés dans cette étude. Il permet habituellement de prélever une part importante des revenus, quand ils sont élevés, et une plus faible part, quand ils sont faibles.

Les législateurs ont essayé d'adapter le prélèvement aux rentes économiques, grâce à la taxe spéciale sur les profits exceptionnels. Alors que ce procédé fonctionne raisonnablement bien, il demeure toutefois insuffisamment flexible pour réagir automatiquement aux multiples conditions de fonctionnement qui se présentent dans ce pays. Le besoin de modifications discrétionnaires continuera à se faire sentir, du fait des changements dans l'environnement opérationnel.

Le système norvégien relatif aux nouveaux gisements est aussi entièrement relié aux profits. Le prélèvement moyen de ce pays continue à être très élevé et sa souplesse d'adaptation à l'environnement opérationnel demeure faible. Ce système est relié aux profits mais pas à la rentabilité. Par conséquent, il n'est pas directement établi en fonction des rentes économiques. Le danger existe qu'il ne tienne pas suffisamment compte des différentes conditions de coûts dans les opérations particulières de l'ensemble du champ pétrolifère. Etant donné le niveau élevé des prélèvements, des effets anti-stimulants pourraient encore apparaître. La faible possibilité d'adaptation automatique signifie probablement que des changements discrétionnaires devront intervenir, le cas échéant.

En Chine, le système comprend une royalty, un plan de partage de la production, un impôt sur le revenu et une participation. Ce mécanisme est régressivement lié aux rentes économiques. Il est, en soi, rigide vis-à-vis des changements majeurs dans l'environnement opérationnel, particulièrement ceux dus à d'importantes variations dans les prix du pétrole. Cette formule engendre un prélèvement fiscal relativement modeste sur les plus petits gisements à coûts peu élevés, mais elle ne permet pas de percevoir des revenus d'une manière précise. Un système qui serait plus étroitement adapté aux rentes économiques pourrait fonctionner d'une manière plus efficace, économiquement parlant, et sans doute permettre de percevoir une plus grande part des revenus.

En Malaisie, le système est complexe et comprend une royalty, un plan de partage de la production et un impôt sur le revenu. Le niveau de prélèvement est très élevé et le système est régressif par rapport aux rentes économiques. Il présente un très net manque de flexibilité dans les secteurs où il en faudrait. Par exemple, si l'exploitation devait se faire en eaux plus profondes, ou si les prix du pétrole devaient encore baisser, il se produirait de réelles distorsions économiques. Le système n'est efficace qu'à l'intérieur d'une gamme étroite de prix pétroliers et de coûts. En cas de changements importants dans l'environnement opérationnel, des mesures discrétionnaires devront intervenir.

En Indonésie, il y a une formule de partage de la production et d'impôt sur le revenu. Le système a été établi en fonction des profits, mais il n'est pas directement relié aux rentes économiques tel que les investisseurs les entendent. Le niveau de prélèvement est élevé et il n'a pas beaucoup de flexibilité dans le sens désiré, en cas de changements dans l'environnement opérationnel. Si l'exploitation devait se faire en eaux profondes ou si les prix du pétrole venaient encore à baisser, il faudrait alors procéder à des changements discrétionnaires pour éviter l'apparition de distorsions importantes.

En Egypte, il y a un système de partage de la production relié aux profits mais pas directement aux rentes économiques. Il en résulte une rigidité dans l'adaptation, en cas de changements dans l'environnement opérationnel. Il faudrait y apporter des modifications pour éviter des distorsions en cas de variations importantes des prix pétroliers ou des coûts.

Au Nigéria, le système comprend une royalty et une taxe spéciale reliée aux profits. Le niveau de prélèvement est très élevé et le système, en soi, n'est pas très flexible par rapport aux changements dans l'environnement opérationnel. Il n'est pas basé directement sur les rentes économiques. En réponse aux chutes de prix récentes, des règles complexes ont été instituées pour réduire la taxe sur les profits réels, afin d'éviter les distorsions économiques. Ce nouveau mécanisme s'avère très compliqué, sans être véritablement relié aux rentes économiques. Des changements discrétionnaires devront intervenir ultérieurement pour répondre aux variations importantes dans l'environnement opérationnel.

En Alaska, il y a une royalty, une taxe à la production, un impôt d'état sur le revenu, un impôt fédéral sur le revenu aussi bien qu'un système de soumission particulier. Les composantes fiscales de l'ensemble engendrent un fort taux de prélèvement et créent un système qui est régressif dans ses rapports avec les rentes économiques. Celui-ci n'est pas très flexible par rapport aux changements de l'environnement opérationnel. Le niveau très élevé de prélèvement est justifié par le potentiel des ressources, mais si les coûts de l'unité d'exploitation venaient à augmenter sensiblement, ou si les prix pétroliers continuaient à stagner, des changements discrétionnaires pourraient bien s'avérer nécessaires.

Pour la plate-forme continentale des Etats-Unis, il existe un système de soumissions avec bonifications, de royalties, d'impôt fédéral sur le revenu et de taxe sur les profits exceptionnels. Ce système est relié d'une manière régressive aux rentes économiques. L'aspect fiscal dans le prélèvement global est relativement modéré pour les situations d'exploitation les plus courantes, et cela prévient l'apparition des distorsions. Bien que les royalties et le mécanisme fiscal soient susceptibles d'avoir des effets négatifs dans les cas d'exploitation en eaux profondes, le risque de voir ceci se réaliser est moins important que dans les autres juridictions. L'efficacité de l'ensemble dépend du bon fonctionnement de la procédure des soumissions.

Au Texas, le système fiscal comprend une taxe locale sur la propriété, une taxe d'état sur la production, un impôt fédéral sur le revenu et une taxe sur les profits exceptionnels. Les royalties, en général, sont dues à des propriétaires privés. Sur des gisements raisonnablement rentables, les prélèvements ne sont pas particulièrement onéreux; c'est seulement sur les terrains marginaux que les effets anti-stimulants apparaissent. La taxe sur la propriété est bien établie en fonction des rentes économiques, alors que les autres mesures n'y sont pas.

Sous le système fiscal de l'Alberta, la royalty provinciale est le facteur dominant. Sa formule est fonction du volume de production des puits, des prix du pétrole et de la date de la découverte du gisement. Le système contient certains facteurs progressifs. Le crédit d'impôt sur les royalties, les remboursements de royalties et les périodes sans royalties aident à réduire le caractère régressif potentiel du système, en termes de valeur réelle, puisque ces allégements sont, en général, octroyés en début d'exploitation d'un gisement. Combiné avec les allégements de démarrage pour l'investisseur, la formule utilisée avant et depuis le PEN a présenté un aspect légèrement régressif dans les conditions de coûts habituelles. Si les coûts devenaient plus onéreux, le système deviendrait beaucoup plus régressif. La formule des royalties, ainsi que les divers allégements et subventions, offrent une flexibilité certaine dans la direction voulue, mais ils ne sont pas suffisants pour faire face automatiquement à une grande variété de situations opérationnelles. Pour ces raisons, il faut s'attendre à des mesures discrétionnaires, en réponse aux changements majeurs dans l'environnement opérationnel.

Dans le système de l'Alberta postérieur au PEN, où les périodes exemptes de royalties sont importantes, le prélèvement fiscal est souvent très modéré dans la plupart des situations ordinaires d'exploitation. L'efficacité de l'ensemble du système de perception des rentes économiques dépend du bon fonctionnement du mécanisme des soumissions avec bonifications.

Un trait notable du système albertain, avec sa prolifération de déductions et de bonifications, est sa grande complexité. Il en résulte que les coûts de sa mise en application sont élevés. Les stimulants à l'exploration fonctionnent bien, mais on peut penser qu'un système plus directement relié aux rentes économiques permettrait d'atteindre les objectifs visés plus simplement et sans recourir si fréquemment aux mesures discrétionnaires.

Sous le PEN, le système fiscal de l'Alberta comprenait la taxe sur les revenus pétroliers généraux. Ce n'était pas une simple taxe sur la production, mais elle n'était toutefois pas reliée aux rentes économiques. Par conséquent, l'ensemble du système ne se rattachait pas aux rentes. L'octroi des avantages au titre du PIP a permis d'éviter l'apparition de distorsions plus sérieuses. La création de cette formule est un bon exemple de ces mesures correctives si importantes dans les mécanismes fiscaux de l'industrie du pétrole au Canada, depuis quelques années. Comme cela a déjà été souligné, il est possible d'arriver à des résultats plus efficaces et moins coûteux avec un système plus simple et plus directement relié aux rentes économiques.

Dans les Terres du Canada, la royalty sur les investissements pétroliers s'est révélée en soi être un instrument raisonnablement efficace. Quand elle s'est combinée avec la royalty conventionnelle, des distorsions ont pu apparaître dans les cas où l'exploitation n'était pas vraiment rentable. Quand on y a ajouté la taxe sur les revenus pétroliers généraux, les risques de distorsion économique se sont trouvés sensiblement accrus. La TRPG n'est pas suffisamment sensible aux changements majeurs dans l'environnement opérationnel pour prévenir l'apparition des effets négatifs.

Le système en vigueur sur les Terres du Canada, depuis le PEN, est beaucoup plus sensible aux changements de l'environnement opérationnel. La diversité des situations qui peuvent se présenter dans ces territoires est cependant très grande. Il y a d'énormes différences dans l'importance des champs pétrolifères et dans les coûts, selon l'emplacement géographique. Pour remédier à cette disparité, la seule mesure significative paraît être le crédit d'impôt à l'investissement. Elle constitue un stimulant important pour les projets dont les coûts de démarrage sont très onéreux, et elle a une influence sur l'ampleur du prélèvement fiscal, en termes de valeur réelle.

La complexité du système fiscal et des bonifications, dans le système postérieur au PEN, s'avère régressive pour les exploitations côtières, et des effets négatifs peuvent en résulter quand les gisements sont marginaux. Comme pour l'Alberta, le système de stimulants à l'exploitation fonctionne très bien depuis le PEN. Le Canada, dans ce domaine, est plus favorisé que la plupart des autres pays pétroliers.

Les systèmes fiscaux examinés partagent les risques d'exploitation du pétrole entre les investisseurs et les gouvernements, selon des modalités qui dépendent essentiellement de la structure des mécanismes qu'ils prévoient. Ceux qui s'appuient principalement sur la production laissent la majorité des risques aux investisseurs. Ceux qui sont globalement reliés aux profits et qui permettent de déduire les coûts d'exploration et de développement d'un projet particulier des revenus d'autres projets obligent les gouvernements à une plus grande participation aux risques. Les systèmes centrés avant tout sur la production ont souvent paru être plus susceptibles aux risques de distorsions économiques. Une remise en question des conditions devrait être prévue en ce cas. Par contre, un système qui demande au gouvernement de tutelle une participation élevée aux risques devrait avoir pour contrepartie la possibilité pour celui-ci de percevoir une plus grande part de la rente économique.

La découverte la plus importante de cette étude, c'est que les mesures fiscales et para-fiscales prises par beaucoup de pays producteurs de pétrole ne permettent pas de procéder à une perception adéquate des rentes économiques provenant de l'exploitation de cette ressource. Les moyens utilisés pour ce faire ne sont habituellement pas fixés en fonction des rentes économiques, et ceci explique cela, d'où le besoin de recourir ultérieurement à des mesures discrétionnaires. Ce besoin se trouve amplifié quand l'environnement opérationnel est l'objet de variations sensibles. D'un autre côté, les mécanismes fiscaux qui sont plus directement adaptés aux rentes économiques réduisent la nécessité de recourir aux mesures discrétionnaires gouvernementales et améliorent, dans l'intérêt de tous, le climat de l'investissement.

Une combinaison de soumissions avec bonifications et de taxe sur les revenus provenant des ressources paraît être la meilleure solution pour parvenir efficacement à percevoir des rentes économiques, sans risque de distorsions. Les soumissions avec bonifications peuvent procurer des revenus avant même le démarrage de l'exploitation et fournir très rapidement aux gouvernements, ou à tel autre propriétaire de ressources, de l'argent liquide, en contrepartie de la remise aux investisseurs des droits d'exploitation des ressources. La taxe sur les revenus provenant des ressources fournira ultérieurement des rentes économiques, en assurant aux gouvernements un fonds de roulement pour les années à venir.

La mise au point satisfaisante d'une formule de taxe sur les revenus provenant des ressources soulève plusieurs questions techniques délicates. Si le taux minimal n'est pas clairement indiqué, les revenus seront évalués d'une manière inexacte, avec risque soit d'un prélèvement fiscal trop faible, soit d'un prélèvement qui découragera les investisseurs. Les gouvernements préfèrent de beaucoup la stabilité dans les revenus. Cela n'est généralement pas possible dans le secteur du pétrole, cependant des mesures comme les paiements de revenus anticipés à provenir des ressources—sur la production initiale et ensuite déductibles des obligations fiscales résultant de la taxe sur les revenus provenant des ressources—peuvent aider à étaler le rendement des revenus d'une manière plus uniforme. L'emploi du procédé d'avance sur taxes pour les produits pétroliers, où les paiements anticipés sont par la suite déduits du montant de la taxe sur les revenus pétroliers, tel qu'il est utilisé au Royaume-Uni, est une bonne illustration de ce type de procédé.

Chapter 1

Introduction

The distribution of the benefits from petroleum exploitation has been a live issue ever since the birth of the modern petroleum industry in 1859, when the first well was drilled by Edwin Drake near Titusville, Pennsylvania. Throughout its history the international petroleum industry has never approached the textbook model of perfect competition. The industry's early years are memorable for the attempts made by J.D. Rockefeller to dominate it in the United States. In the late 1920s a few major companies made an agreement, known as the Pool Association, which attempted to regulate the world market outside the United States and the Soviet Union.[1] In the period from the end of the Second World War to the late 1960s, the seven largest international companies exercised a dominant influence on world production outside the United States and Russia and arguably, through their joint venture arrangements in the Middle East, restrained competition.[2] In the 1970s the Organization of Petroleum Exporting Countries (OPEC), a group of major producing countries, emerged as the dominant force in the world market. In recent years restrictions on production imposed by OPEC members have constituted a major limitation on competition.

These restraints on competition have had major effects on the allocation of resources throughout the world. Oil is both a key source of energy and, by value, the most important internationally traded commodity in the world. Either directly or indirectly, its price has an important effect on the balance of payments of most countries. In many nations oil production makes a significant contribution to the level of national output and to government tax revenues. If the total world output of crude oil in 1984 had been valued at $30* per barrel, the total production of 58.1 million barrels per day (b/d) would have been valued at $632.9 billion.

The changes in oil prices which have occurred in the last 15 years have had significant repercussions on the distribution of wealth and the growth of the world economy. These changes have also had major effects on the structure of the petroleum industry. Thus the quadrupling of oil prices in 1973-1974 attracted exploration for petroleum into high-cost areas of the world, where exploration would previously have been uneconomic. The result is that exploration and production now take place in regions of the world with a vast range of exploitation costs. In 1985 estimates by a major investor[3] put the total average costs of Middle East oil in the range of $1 to $5 per barrel (at 1985 prices) and those of North Sea oil in the range of $5 to $40 per barrel; costs of oil from enhanced recovery, tar sands, and oil shale were estimated to be in the range of $25 to $95 per barrel. The collapse of world oil prices in 1986 has led to significant decreases in development costs of new fields, partly due to improvements in technology and partly because of falls in the prices of inputs.

The very large differences in exploitation costs have obvious implications for the distribution of the benefits from oil production. Exploitation in low-cost areas was extremely profitable after the 1973-1974 price increases. At the same time, in their search for revenues, host governments increasingly turned their attention to the petroleum sector. In the second half of the 1970s the industry worldwide was subjected to a proliferation of tax increases and newly imposed taxes. The resulting fiscal packages were generally highly complex and their full effects were not immediately appreciated. Marginal rates have been extremely high, in some instances in excess of 90 per cent. The danger of distortions emerging in the allocation of resources is correspondingly high.

As part of more general economic policies, some governments, notably Canada and the United States, retained price controls on crude oil at levels well below world market levels. In these circumstances oil purchasers were obtaining through the government regulations some of the benefits of domestic petroleum exploitation. This also introduces potential distortions in the allocation of resources.

Since petroleum is such an important commodity in most economies of the world, the issue of the distribution of the benefits from its exploitation is important quantitatively as well as qualitatively. In the United Kingdom, for example, taxes from petroleum exploitation accounted for around 10 per cent of total central government tax revenues in 1984-1985. In Norway the corresponding figure has exceeded 20 per cent. In Third World countries involved in petroleum production, dependence on oil revenues is much greater: in 1985 petroleum accounted for 97 per cent of Nigeria's foreign exchange earnings; in Indonesia between 60 per cent and 70 per cent of both foreign exchange earnings and budgetary revenues came from oil and gas exploitation in 1985. Dependence on petroleum revenues has, of course, increased dramatically since 1973. Thus, Indonesia was producing as much petroleum in the early 1970s as in 1985, but in the earlier period oil contributed only about 35 per cent of her foreign exchange earnings and 25 per cent of budgetary revenues.

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* Unless otherwise specified, dollar amounts are in US$ throughout this study.

The world price of oil has exhibited spectacular movements since the early 1970s. As late as 1972 it was around $2.50 per barrel. By January 1974 the official price of Saudi light was $10.84 per barrel. By January 1980 North Sea oil was selling for $29.75 per barrel and by January 1981 the contract price was $39.25. Nigerian crude actually fetched $40 per barrel in early 1981. This has been the peak to date. Since that time the movement has generally been downward, until the summer of 1986. North Sea spot prices briefly reached $30 per barrel in November 1985 but a dramatic fall ensued after the break-up of the OPEC meeting in December of that year. By February 1986 North Sea prices were around $16 per barrel and fell to less than $10 per barrel in the summer. Prices recovered, however, and by the end of the year a figure of $18 per barrel was reached. This average level was generally maintained in the first half of 1987, though in terms of many other currencies the value of oil fell due to the depreciation of the U.S. dollar.

These major price movements have brought correspondingly large changes, not only in the rewards from petroleum exploitation, but also in the distribution of these benefits between governments and investors. The type of fiscal system employed by each government has largely determined this distribution. Some fiscal systems have automatically reacted, in a moderately sensitive manner, to changes in oil prices. Others have been rather insensitive, and discretionary intervention by government has been required to prevent the emergence of disincentives to explore for and produce oil.

Governments all over the world are anxious to collect a high share of the economic rents emanating from petroleum exploitation. These rents have been highly variable, both over time and within any producing province at any given time. The potential revenues from efficiently capturing these rents may be large. The costs of failing to do so are also large, not only in the form of lost revenues but also in any disincentive effects introduced.

This study analyzes the mechanisms employed to extract petroleum rents in a number of significant producing countries, with the several schemes employed in Canada being given detailed attention. Petroleum exploitation is an important activity in all the countries examined. Both advanced industrial countries and developing ones were selected, and two OPEC members – Nigeria and Indonesia – were specifically included. The countries were chosen to encompass a wide range of fiscal devices, although countries where petroleum production has been nationalized have not been included in the study – the prime objective has been to concentrate attention on the delicate relationship between private investors and governments; in countries where the industry is nationalized the focus of interest is rather different. The working of the various systems was tested against the background of fluctuating oil prices and variable cost conditions that is now characteristic of the petroleum industry. The main purpose of the study was to discover how efficiently the various schemes perform. Therefore, any distortions that may exist, such as disincentives to exploration and to new field development, are highlighted. The analysis indicates the distribution of the economic rents among investors, governments and, where appropriate, consumers and private landlords.

Notes

1. For a concise discussion of J.D. Rockefeller's activities and of the operation of the Pool Association (or Achnacarry Agreement) see C. Tugendhat and A. Hamilton, *Oil: the Biggest Business* (London: Eyre, Methuen, 1975).

2. For a detailed discussion of this subject see M.A. Adelman, *The World Petroleum Market* (Baltimore and London: The Johns Hopkins University Press, 1972).

3. Shell International Petroleum Co. Ltd., *Energy in Profile*, Shell Briefing Service No. 4 (London, 1985).

Chapter 2

Economic Rents in the Petroleum Industry

Definition and Nature of Economic Rents in Petroleum Exploitation

Economic rents are conventionally defined in the economic literature as returns accruing to a factor of production in excess of its transfer earnings. These earnings will generally refer to those obtainable in the factor's next most valuable alternative use, following the Paretian interpretation of the concept. The original Ricardian analysis referred to the difference between what a factor earns and what is necessary to bring it into employment. The common-sense meaning of the concept is that the revenues earned from the exploitation of a natural resource can be divided into two parts. The first is a functionally necessary cost component required to find, develop, and produce the resource: to allocate capital and labour to resource exploitation, they must be paid a sum sufficient to bid them away from their most highly valued alternative use. The second component is the residual difference between this total economic cost and the revenue received. When revenues exceed the total economic cost, positive economic rents are being earned. This total economic cost is the necessary supply price in the industry concerned, and the economic rents are any remaining surpluses. In considering the supply price it is important to distinguish genuine economic rents from quasi-rents. The latter constitute earnings which have no short-term effects on the supply of investment to a particular activity but do influence investment supplies in the longer term.

Economic rents are ubiquitous but natural resource extraction in particular has long been viewed as an activity that is likely to generate some rents. It is also generally acknowledged that it is legitimate for a government to extract at least a large share of these rents for the benefit of the general citizen. The consequence should be that revenues are raised without causing any distortion in the allocation of resources. This indicates an important criterion by which the comparative efficiency of different rent-collecting devices may be measured.

The attractive possibility of raising revenues in a distortion-free manner is frequently stated in very general terms. In practice the measurement of rents in any industry is by no means straightforward, and there certainly are difficult problems regarding the application of the concept of petroleum exploitation. Oil is a non-renewable resource, the full stock of which is not completely known at any one time. Further, it is not homogeneous in the sense that exploration and exploitation costs can differ markedly not only among different regions but inside any one geographic area. In addition, the market for the product generally does not correspond to the textbook definition of perfect competition.

In most countries of the world petroleum rights are owned by governments, and in disposing of their rights governments are likely to have multiple objectives, some of which may conflict. The collection of a high share of the economic rents is certainly a major objective in all producing countries. Other common objectives are to regulate the pace of exploration and development, to ensure security of supply for the domestic market, to influence the domestic price of petroleum, to obtain significant local ownership of an important resource, and to enhance local participation in employment and provision of supplies and equipment. It is clear that the maximization of revenues from petroleum exploitation is likely to be inconsistent with some of these other objectives. For example, domestic price controls or the imposition of requirements to purchase supplies of equipment locally will reduce the revenue base below the level it would otherwise have attained.

The economic theory of natural-resource depletion makes some fundamental propositions concerning the behaviour of economic rents over time.[1] In a simplified situation, where there is perfect competition in the market for mineral rights and in the product market, and where there is a known homogeneous stock of the natural resource, profit-maximizing resource owners will release mineral rights in such a way that in equilibrium their unit value increases at the rate of interest. To bring this about a reduction in the volume of rights sold over time is required. If, as is the case with petroleum, the stocks of the natural resource are not homogeneous and unit production costs vary, the owners of the mineral rights will offer those of higher quality first in order to maximize their economic rents in present-value terms. Over time, with rights of lower quality being made available, the inevitable consequence is an increase in the producer's unit production costs. The investor's demand for mineral rights is in the form of a desired demand curve, and the increase in his costs produces a leftward shift in this curve. It follows that the unit value of the rights rises over time at a rate lower than the rate of interest.[2]

In the petroleum industry the total stock is by no means fixed or known. When exploration costs are introduced, the market value of mineral rights depends on whether they are acquired before or after the exploration. Where the landlord pays for the exploration costs, the market value of mineral rights in the initial period is higher than in a world without such costs. Where the extractor pays for the exploration, the value of the mineral rights is correspondingly reduced. The value of mineral rights increases over time more slowly than in the absence of exploration costs. Net of such costs the value would still rise at the same pace as the rate of interest.[3]

It is clear that mineral rents can exist in an environment where both the product market and the market in resource rights are competitive. Because of the large differences in exploitation costs, economic rents are highly differentiated across different localities. Outside North America the oil market has never approached the textbook definition of perfect competition. Within North America competition was strong in the 1920s and early 1930s before the passage of the Connally "Hot Oil" Act of 1935. Since then competition has been restricted by the growth of prorationing in Texas, and subsequently in Alberta, and the import controls in the United States and Canada in the 1960s. In more recent years OPEC has deliberately restricted production in an attempt to prevent prices from falling, and OPEC members have enjoyed monopoly profits as a consequence. A wider effect of these restrictions has been greatly to increase the rewards from exploiting petroleum elsewhere in the world: the values of mineral rights and existing production have been much augmented. Producers to whom rights had already been awarded experienced large windfall profits. These gains cannot be whittled away by competition from other investors, as the institution of property rights prevents new entrants from participating in existing projects except on terms acceptable to the existing holders.

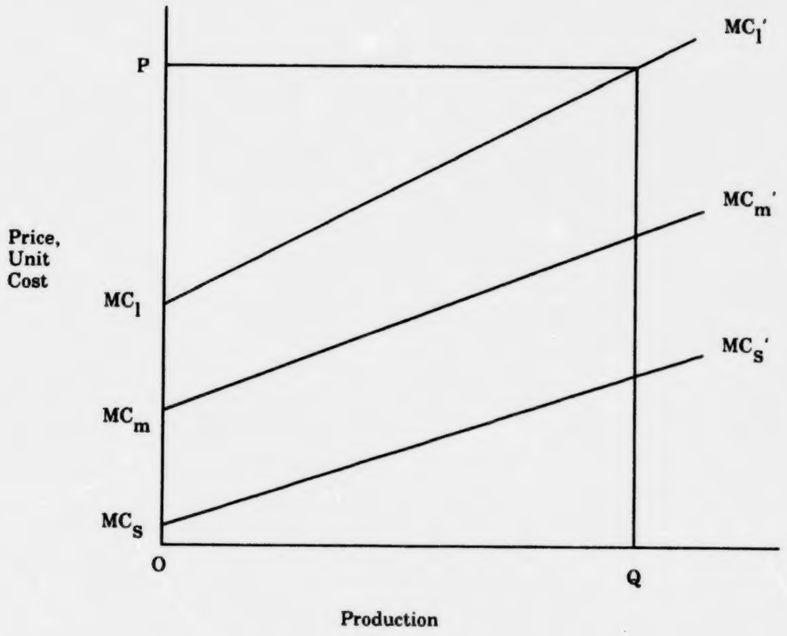
Against the background of highly differentiated rents the definitional problems can now be examined more closely. In the petroleum industry three different supply prices may be distinguished – the short-run, the medium-term, and the long-run supply price. The first relates to the costs of continuing production from existing fields which have been developed in the past. The second relates to the development and operation of new fields which have already been discovered. The third, the long-run supply price, relates to the costs of finding petroleum as well as developing and operating the discoveries in question. The long-run supply price thus includes the full cycle of activities necessary to replace the existing stock.[4] The relevant exploration costs reflect the chances of finding petroleum and the development costs reflect the likely costs of future field developments.

The distinction between the various supply prices is illustrated schematically in Figure 2.1. The ruling of oil price is OP and the industry marginal cost curves are seen to increase without output. The short-term marginal cost curve is MC_s, the medium-term is MC_m, and the long-term one is MC_l. The curve MC_s-MC_s' shows the costs of continued production from existing developed fields. If a government were to collect all the revenue above this cost curve (namely, the area $MC_sPMC_l'MC_s'$), production from the existing fields would continue but no new field developments or exploration would take place. The curve MC_m-MC_m' shows the costs (including capital remuneration) of continuing production from existing fields and developing new fields which have already been discovered. Again, if a government extracted all revenues in excess of these requirements (namely, $MC_mPMC_l'MC_m'$) the result would be that, while developments of existing discoveries would continue, there would be no new exploration. The area $MC_mMC_lMC_l'MC_m'$ represents the quasi-rents of exploration: they are not a necessary cost in the short or medium terms but do constitute a long-term cost of obtaining petroleum. A government can extract these quasi-rents in the short run but only at the expense of reducing exploration and so reducing potential future production and economic rents. The greater the chances of the exploration resulting in "dry holes" or non-commercial finds, the greater the return that an investor will require on discovered fields to compensate for the high risk. True economic rents are shown by the area MC_lPMC_l'. This is the surplus remaining after the returns required to foster continued exploration, as well as new field developments and ongoing production, have been satisfied.

Investment Criteria and Yardsticks in the Petroleum Industry

To understand more fully the supply price of investment in petroleum, it is useful to examine the criteria and yardsticks employed by investors in this industry. The primary goal of oil companies, like other commercial organizations, is to conduct their operations so as to produce maximum or at least satisfactory long-run post-tax returns.

Figure 2.1
Supply Price and Economic Rents in Petroleum Exploitation


MC$_l$'
P
MC$_m$'
Price,
Unit
Cost
MC$_l$
MC$_s$'
MC$_m$
MC$_s$
O
Q
Production

In pursuit of this objective they subject investment opportunities to detailed economic analysis. Decisions are made with reference to a number of economic yardsticks and guidelines. Not all of these will be given equal weight by a given investor, and different companies are likely to place more emphasis on some criteria than on others.[5] The following yardsticks and guidelines are commonly employed in the industry when new field development projects are being considered:

- payback period in money-of-the-day (MOD) terms
- payback period in real terms
- maximum (cumulative) cash exposure in MOD terms
- maximum (cumulative) cash exposure in real terms
- real net present value (NPV) at zero discount rate
- real net present value at various positive discount rates reflecting cost of capital and risk of project
- real internal rate of return
- real profit/investment ratio (real NPV of project divided by real PV of project investment costs)

These yardsticks reflect the factors that are important to companies when they are contemplating investments. Use of the payback period indicates the investor's concern with recouping his initial investment. Calculation of maximum cash exposure indicates concern at the total scale of his funds at risk. Calculation of the net present value at zero discount rate indicates interest in the aggregate amount of cash surplus likely to be generated by the project. Use of a positive discount rate to find the net present value indicates that the investor is concerned with the time value of money as well as with the scale of the project. The greater the level of perceived risk, the higher the discount rate that will be chosen (at least by some investors) to reflect the risk of a project. Such a procedure discriminates against projects with a longer time span before the receipt of the main income flows. Use of the internal rate of return again reflects concern for the time value of money.

In the petroleum industry, investors generally give prominence to discounted-cash-flow techniques. In a recent survey of large U.S. petroleum corporations it was found that 98 per cent gave much weight to at least one variant of discounted-cash-flow analysis. The payback period also was employed by 83 per cent of the firms. All the firms employed a combination of measures to assess projects, reflecting their multiple objectives and the limitations of some of the individual yardsticks.[6]

Of the criteria involving discounting, the most frequently employed are the net present value and internal rate of return techniques. The rate of discount employed to screen the projects is obviously important, and the rate most frequently used by companies in the above-mentioned survey was the weighted average cost of capital.[7] In 1983, for the majority of companies in the survey, this amounted to 16 per cent in money-of-the-day terms. One major company estimated the weighted average cost of capital which it employed to calculate net present values at 10 per cent in real terms for 1985. This figure was determined by its wish to maintain a strong "AA" bond rating, which required a debt/equity ratio of around 25/75, and a need to provide for shareholders a return (in 1985) of around 18 per cent in money-of-the-day terms. This gave shareholders a premium for risk of about 6 per cent above risk-free government bonds at that time.[8] Another major investor reckoned that project screening rates usually ranged from 12 to 15 per cent in real terms.[9]

Risks in Petroleum Exploitation

For fields which have been discovered but which have not yet been developed there are several types of risk faced by the investor.

Reservoir Risks

Two aspects can be distinguished here: the size of recoverable reserves is subject to considerable uncertainty before production commences, and so is the flow rate. As production experience is gained, the uncertainty about the size of reserves is progressively reduced, but the flow rate is still subject to unexpected change.

Development Cost Risks

In operations in Alberta and Texas, field development costs are comparatively low and the lead times relatively short; a period of only a few months may elapse between development outlays and initial production. In offshore situations development costs are very high and lead times long; the elapsed time between first development expenditure and initial income can range from two to six years. Development cost risks are most pronounced in "frontier" areas where experience of the operating environment is limited or where new technologies are being employed. Project completion risks are also generally higher in the same circumstances. Both development cost overruns and delays in project completion were common in the case of the North Sea in the first half of the 1970s and would have seriously jeopardized the viability of some projects had it not been for the large oil-price increases which took place at the same time.

Oil Price Risks

Large oil-price movements have been a major feature of the operating environment over the last 15 years. The changes which have taken place have not been anticipated by investors. For example, in 1980 it was widely forecasted that by 1985-1986 prices would be in excess of $50 per barrel (in 1985 dollars). In fact, as mentioned above, prices never topped $40 per barrel and were generally below $30 per barrel in 1985. Thus oil price risks constitute one of the main features of the development decision.

Political Risks

This form of risk has been defined to exist "(1) when discontinuities exist in the business environment, (2) when these discontinuities are difficult to anticipate, and (3) when they result from political change."[10] Political risk in this sense is not synonymous with political instability: a country could be politically stable in the sense that revolutions do not occur, but major swings in economic policies could still take place. Oil companies react to this type of risk by altering their discount rate. A major company, Exxon, in the event of fears of "a radical change in government or tax policy may add one to five percent to its required rate of return."[11]

Economic Analysis of the Exploration Program

When contemplating an exploration program, investors have to consider all the factors discussed above in addition to the most basic risk, namely, that of finding petroleum in commercial quantities. At the exploration phase the investor has to consider not only the chance of finding oil but also the likely sizes of fields, their exploitation costs, and the revenues which could be obtained. In these circumstances an approach favoured by major investors is to calculate the expected monetary value from an exploration program.[12] In essence this can be represented as follows:

$$\text{Expected Monetary Value (EMV)} = P\,(NPV) - E$$

where P represents the probability of discoveries being made, NPV is the net present value from developing discovered fields (excluding exploration costs), and E is the cost of the exploration program in present-value terms. Thus, if the probability of commercial discoveries being made was 20 per cent, the net present value from developing such discoveries was $100 million and the exploration cost was $10 million, the expected monetary value would be $10 million.

However, when a prospect is being appraised there will always be uncertainties surrounding the probability of a successful find and the volume of recoverable reserves. The information available will always be insufficient for precise estimates of the required variables to be made, since the information will usually be in the form of probability distributions. In these circumstances Monte Carlo analysis can be undertaken with the data. There are several other methods by which a prospect may be appraised, and the method employed is likely to depend on the size of the area to be assessed and the amount and type of information available (such as drilling data).[13] Formerly, investors employed subjective methods relying on the intuitive thought processes of geologists. Sophisticated investors nowadays employ statistical methods or deterministic models.

With a statistical method, extrapolations are made on the basis of past experience (incorporating, for example, trends in the success ratio and size of field discovered). The validity of this method depends on the length of exploration history available, and the method suffers from the disadvantages that the interrelationships between variables may not be known and correlations might be fortuitous.

For these reasons a completely deterministic model – which integrates all the relevant geological concepts and findings in order to construct a picture of the process of hydrocarbon generation, migration, and retention – is desirable. Because of the lack of necessary information for this major task, at least one major explorationist has employed a simplified model, which is calibrated against an extensive worldwide data set which tests the significance of the hypotheses implied by the model and defines the range of uncertainty resulting from its incompleteness.[14] The results of such a calibration study are then employed to update worldwide "prior" distributions by means of a Bayesian process using information specific to the area being appraised.

The results of the appraisal using Monte Carlo analysis will be a probabilistic series of equally likely volumetric outcomes, which can be presented as a cumulative frequency distribution. The mean value of all the outcomes (including the zero ones) can then be calculated. The mean of all the successful outcomes, a more useful mean, can also be calculated. At least some explorationists will define a successful outcome to be not just any discovery but a discovery that is commercially viable under their existing perceptions of future costs, oil prices, and taxes payable. The cumulative frequency distribution is adjusted to take account of the fact that some finds will have a zero economic value. The effect of this is to reduce the mean of the whole distribution: the probability of success is less and the mean success volume will be increased.

With these estimates of the probability of discoveries being made, the expected monetary value (EMV) can be calculated. The calculation takes into account takes levied by governments and includes the relevant deductions for exploration costs. The investor's discount rate is determined in the same way as that discussed for the field development decision. When the EMV is positive, the exploration program would be undertaken.

Analysis of the Effect of State Participation

A frequent feature of petroleum exploitation arrangements is equity participation by a national oil company. At the exploration stage the investor's supply price also includes the effects of this participation, and these effects depend on the terms on which participation takes place. Clearly the net present value that the investor can expect from developing a discovered field is reduced by the participation of a state company. Participation in petroleum exploitation is frequently by the carried-interest method, by which the investor carries all the exploration risks up to the point at which a commercial discovery is made. At this stage the national company obtains an equity stake at a given rate and contributes its share of all costs from that time. Depending on the terms of the agreement, the state company may or may not reimburse the investor for its share of past exploration costs.

The effect of participation on the investor's incentive to explore can be quite strong, depending on the degree of participation and the rules governing the sharing of exploration costs. For example, suppose that, as in Norway in the Tenth Round, the rate of participation is 65 per cent commencing when a commercial discovery has been made. Suppose that the investor is not reimbursed for bearing the state's share of exploration costs. The EMV facing the investor in this situation is as follows:

$$EMV = P(NPV)(1 - GP) - E$$

where GP is the rate of state company participation in the field. Using the same numbers as were employed in the EMV example above, the EMV now becomes -\$3 million (whereas without participation the EMV was +\$10 million). If the state company participated as a full risk-sharing partner from the commencement of exploration, the EMV facing the investor would be as follows:

$$EMV = P(NPV)(1 - GP) - E(1 - GP)$$

In this case the resulting EMV is +\$3.5 million. In some countries, such as Nigeria, the state company reimburses the investor for its share of exploration costs in the event of a commercial discovery but not where the exploration is abortive. In this case the EMV facing the investor is:

$$EMV = P(NPV - E)(1 - GP) - (1 - P)E$$

and the resulting EMV is -$1.7 million.

Thus, participation has potentially powerful effects on incentives for investors. These effects occur because the state company is normally sharing in the rewards of discoveries but not sharing fully (if at all) in the costs and risks of exploration. The simple examples above have not included the complications of taxation. The investor does, of course, obtain tax relief on all his exploration outlays and such relief is included in the EMV calculation.

Public-Sector Investment in Petroleum

So far, in the consideration of the supply price of investment it has been implicitly assumed that the resource is being exploited by private-sector organizations and thus private discount rates are appropriate in the determination of economic rents. It is not, of course, necessary to rely completely on private investment to explore for and produce petroleum. Government involvement can take many forms, including the provision of infrastructure with and without user charges, equity participation, and publicly financed exploration.[15] It is sometimes argued that public-sector involvement is desirable because social discount rates are lower than private ones and because at least some forms of public-sector involvement can reduce discount rates and thus increase the economic rents available.

With regard to investment in petroleum exploitation, it is specifically the absence of the political risk factor that contributes to lower public discount rates. This phenomenon is likely to be important in Third World countries, especially in situations where petroleum projects are large and attract much public attention.

Government investment in petroleum exploitation can be direct, through equity stakes, or indirect. If the government is a full risk-sharing partner, direct equity investment could result in the overall supply price of investment being reduced. In addition to enjoying the conventional risk-sharing benefits from having a joint-venture partner, a private investor may feel that a partner in the form of a government corporation confers benefits in the form of enhanced security surrounding the operation. At the same time, if the government corporation participates on preferential terms, the result could be that the private investor perceives the risk/reward ratio to be altered adversely. The consequence could then be that the private discount rate would be increased.

Direct government investment in exploration is sometimes argued for in circumstances where the risks are perceived to be especially high and where the private discount rate is correspondingly high. One well-known writer has put forward the additional argument that there are substantial economies of scale in basic geological mapping and so public investment is particularly suitable in this area. The benefits would accrue in the reduction of large risk premiums imposed by private investors. The government's risks would be spread, and benefits could be obtained through the operation of the "law of large numbers."[16]

Indirect government investment would typically take the form of provision of infrastructure. The effect on the private investor's supply price depends on whether direct charges are made for the services in question. With no charges, the investor's costs are clearly reduced and potential economic rents increased. If charges are made, the result depends on whether the government or the private investor can provide the service more cheaply, taking into account the difference between government and private discount rates.

Third World governments may sometimes be able to obtain loans in the form of aid on concessional terms. These can contribute to lower discount rates being applied to petroleum investments. On the other hand governments may be highly risk averse in their attitudes to investment in petroleum, especially in situations where they have had no experience of this type of activity. Even when a government obtains aid funds on concessional terms it may feel that the risks of investing in exploration projects are too high, particularly if the government's overall international debt position is highly adverse.

In general, government investment is justified if it takes place at an economic cost lower than private investment; the result will be an increase in the available economic rents. Such investment at lowest real resource costs leads to the maximization of potential economic rents. It is quite likely that a combination of the various types of public investment will prove optimal.

Who Should Receive Economic Rents?

The question of who should receive the economic rents from petroleum exploitation arouses much emotion. The beneficiaries can be investors, oil consumers, and governments. Quasi-rents may also be earned by suppliers of goods and services which are in short supply when oil exploitation is undertaken.

Investors

Of course, in the absence of any legislation, investors would receive the total amount of economic rents from petroleum exploitation. It is generally accepted that governments can legitimately collect "pure" economic rents from investors. However, enough has already been said to emphasize that in practice the measurement of pure rents is no easy task; great care is required in devising schemes, in order to ensure that only pure economic rents are extracted and that functionally necessary returns, namely quasi-rents or normal profits, are not also extracted.

Consumers

In some oil-producing countries oil consumers have effectively received a share of the economic rents in the form of prices lower than would otherwise have obtained. As far as sellers of crude oil are concerned, controlled prices below free-market levels have been common in many countries over the last decade, including Canada, the United States, Indonesia, Australia, and Nigeria. The precise arrangements have varied considerably from country to country. Sometimes the price regulation applies only to a share of production, as in Indonesia and Nigeria. In some cases the beneficiary of the "low" producer price has been the final consumer of petroleum products. In other cases, such as Australia in the 1970s, an "old" oil producer received a price below the world level while the refiner paid the full import-parity price equivalent, with the whole difference being taken as a duty.

The extent to which oil consumers share in the economic rents from petroleum exploitation is measured by the difference between the prices actually paid and those that would have prevailed in a free market. In general, the receipt of petroleum rents by consumers represents a diversion of that rent. The result of settling oil prices below market levels is to cause a misallocation of resources. When the price of a product is kept artificially low, its value does not reflect its opportunity cost. Whether the product is used as a final consumption good or as an intermediate product, the pattern of its use is such that it does not reflect its relative scarcity value. In the case of petroleum the result is that consumption of petroleum products is stimulated at the expense of substitute goods and at the expense of investment in conservation.

Governments

Where there is only one jurisdiction in a country, the problem of collecting economic rents for the benefit of taxpayers generally boils down to the question of the most efficient mechanism for achieving this objective. The issue is much more complex when more than one jurisdiction exists in a country. What are the respective claims of each authority, firstly, to extract the rents and, secondly, to retain the revenues within its own jurisdiction? These questions have no easy answer.[17] An obvious starting point is the constitutional position, but this does not adequately resolve the issues. In Canada, for example, both provincial and federal governments have the right to levy taxes on natural resource extraction, and the rights of provincial governments in this area were recently extended.[18] However, there is no indication of how the taxing rights should be exercised. Conferring to more than one jurisdiction the right to tax a particular activity, far from resolving the problem, opens up the possibility of conflict between the different tiers of government. More fundamentally, the current constitutional position in a country does not answer the question of what the most sensible arrangement would be.

Another obvious constitutional starting point concerns the allocation of property rights. In Canada such rights are generally vested in the Crown in right of the provincial governments, with the federal government having the rights on the Canada Lands; in a few areas private landlords have mineral rights and there are aboriginal rights and claims in other areas. The state governments have property rights in Australia. The ownership of property rights clearly brings with it the receipt of economic rents from the disposal of these rights, and private landlords should expect these rents to be subject to tax. Where the landlord is a government, it could argue that it is legitimately receiving the rents on behalf of the population for which it is responsible. The fact that the government in question has been given the mineral rights under the constitution justifies its collecting the rents.

However, it could also be argued that, while a defined tier of government generally has the rights of a landlord, this does not mean that only the population within that jurisdiction has the right to capture all the economic rents from natural resource exploitation. The appropriate community for this purpose could be defined as the largest political entity within which members are treated equally.[19] Thus, where a federal government is responsible for health and social security services and levies a national income tax and where equalization payments take place across state or provincial borders (as in Australia and Canada), there is ample evidence of a national desire for equity across provinces or states. In these circumstances the accident of the location of petroleum deposits should not determine the fiscal benefits from its exploitation; rather, collection should be undertaken by national governments for the benefit of the whole country.

This argument is not foolproof. The existence of national taxes and benefits and equalization payments does not establish that economic rents from natural resource exploitation are the prerogative of the national government. These features of the operation of a federal system do, however, lend weight to the argument that economic rents collected in individual states or provinces should be taken into account when equalization payments are determined. It can certainly be argued that in these circumstances "resource revenues should be included in the base used to calculate payments into equalization as well as entitlements for equalization payments."[20] A state or province that receives large revenues from natural resource exploitation is better able to reduce other taxes or provide more public goods than are less fortunate states. This is generally not a convincing argument for giving the rights to such revenues to the national government, but it is an argument for structuring the system of equalization payments to take account of such differences.

If a state government uses its revenues from natural resource exploitation to reduce other taxes, the effect could be to reduce locational inertia and produce a more efficient distribution of resources. It has been argued, however, that downward pressure on the marginal productivity of labour and capital in the receiving states could result, with a resulting geographical distribution of population that is inefficient from the point of view of the whole country.[21] In an investigation of this question in the United States (excluding Alaska), Mieszkowski and Toder found that the locational inefficiencies caused by fiscal disparities related to natural resource exploitation amounted to deadweight losses ranging from 2 to 9 per cent of the total tax revenues, depending on whether the subsidy was allocated to capital or labour.[22] However, care is needed in drawing general conclusions from these findings. As Willett points out[23] the argument is dependent on the assumption that resources are otherwise efficiently allocated; but in at least some countries the marginal product of labour and capital can be higher in states where petroleum exploitation is taking place, and the fiscal effects of state governments' having access to mineral rents could improve the allocation of national resources.

The exploitation of petroleum normally requires the provision of a relevant infrastructure, and government will usually be involved in the financing of this infrastructure. Following from the traditional benefit approach to the provision of public goods and the levying of taxes, it could be argued that the tier of government that is responsible for providing the infrastructure has a corresponding claim to the revenues. Also, petroleum is a depleting resource and, as production diminishes, the local population could become less able to sustain the burden of providing local public goods. If the state or provincial government had to provide infrastructure relating to the exploitation of the resource, the arguments for the same government being able to extract resource revenues are stronger. It has been argued that the problem for such a government will be greater the faster the rate of depletion of the resource and that the local jurisdiction's share of the resource revenues should vary directly with the rate at which the resources become exhausted and with the durability of the related public works.[24]

The doyen of public-finance economists, R.A. Musgrave, has suggested a number of rules for assigning tax powers between different tiers of government.[25] They may be summarized as follows:

1. Middle- and especially lower-level jurisdictions should tax those bases which have low interjurisdictional mobility.
2. Personal taxes with progressive rates should be used by those jurisdictions within which a global base can be implemented most efficiently.
3. Progressive taxation, designed to secure redistributional objectives, should be primarily a central responsibility.
4. Taxes suitable for purposes of stabilization policy should be central, while lower-level taxes should be cyclically stable.
5. Tax bases which are distributed highly unequally among sub-jurisdictions should be used centrally.
6. Benefit taxes and user charges are appropriate at all levels.

Most of these rules are consistent with a system whereby state or provincial governments collect resource rents. In the case of petroleum the fifth rule is likely to cause a problem in this respect as it frequently happens that geographic incidence of deposits is very unequal within a country. The problem of unequal tax bases is probably most efficiently dealt with by incorporating resource revenues in some measure in the system of equalization payments.

Notes

1. For a detailed and illuminating discussion of the behaviour of economic rents under different assumptions regarding the structure of a natural resource industry see H.F. Campbell, W.D. Gainer, and A. Scott, "Resource Rent: How Much and for

Whom?" in *Natural Resource Revenues: A Test of Federalism*, ed. by A. Scott, British Columbia Institute for Economic Policy Analysis Series (Vancouver, B.C.: University of British Columbia Press, 1975), pp. 118-36.

2. See Campbell, Gainer, and Scott, pp. 127-29. See also W.D. Schulze, "The Optimal Use of Non-renewable Resources: the Theory of Extraction," *Journal of Environmental Economics and Management* 1 (1974), pp. 53-73.

3. For a detailed discussion see Campbell, Gainer, and Scott, "Resource Rent."

4. The need to consider replacement costs in the measurement of economic rents is discussed in C. Watkins and B. Scarfe, "Canadian Oil and Gas Taxation," *The Energy Journal* 6 (Special Tax Issue, 1985), pp. 17-35.

5. For discussions of how two major petroleum investors assess projects see J. van Dam, *Economic Analysis of Oil and Gas Projects*, 2nd edition (The Hague: Shell Internationale Petroleum Maatschappij BV, 1983) and C.S. Nicandros, "An Oil Company Evaluation of Worldwide Exploration Opportunities," *DNC Oil Now* 14 (1985), pp. 1-20.

6. See H.F. Boyle, Jr., and G.K. Schenck, "Investment Analysis: U.S. Oil and Gas Producers Score High in University Survey," *Journal of Petroleum Technology* (April 1985), pp. 680-90.

7. See Boyle and Schenck, "Investment Analysis," p. 683.

8. The calculation is as follows:

   Weighted Cost of Capital (Debt/Equity Ratio 25/75)

Debt (after tax)	6% x 0.25	=	1.5%
Equity	18% x 0.75	=	13.5%
Weighted average			15.0%

   Real cost of capital: 15% (MOD) minus 5% (inflation) = 10%

   (*Source*: C.S. Nicandros, "An Oil Company Evaluation," p. 3.)

9. See van Dam, *Economic Analysis of Oil and Gas Projects*, p. 19.

10. S.H. Robock, "Political Risk: Identification and Assessment," *Columbia a Journal of World Business* (July 1971).

11. L. Kraar, "The Multinationals get Smart about Political Risk," *Fortune* (March 24, 1980).

12. For a discussion of techniques to deal with exploration risk see A.W. McCray, *Petroleum Evaluations and Economic Decisions* (New Jersey: Prentice-Hall, 1975), chapters 5-9.

13. For a general discussion see M.H. Nederlof, "Estimation of Undiscovered Hydrocarbons – Methods and Pitfalls," paper presented at the Sixth Exploration Seminar of the Egyptian General Petroleum Corporation, Cairo, March 7-10, 1982 (Shell Internationale Petroleum Maatschappij, 1982). For a discussion of the subjective approach see E.C. Capen, "The Difficulty of Assessing Uncertainty," *Journal of Petroleum Technology* (1976). For examples of deterministic models see D.H. Welte and M.A. Yuckler, "Petroleum Origin and Accumulation in Basin Evolution – a Quantitative Model," *AAPG Bulletin* 65/8 (August 1981) and P.Y. Chenet, F. Bessis, P. Ungerer, F. Nogaret, and J.F. Perrin, "How Geological Mathematical Models can Reduce Exploration Risks," Special Paper No. 7, Eleventh World Petroleum Congress, London, 1983.

14. See D. Sluijk and M.H. Nederlof, "Worldwide Geological Experience as a Systematic Basis for Prospect Appraisal," AAPG Memoir No. 35, 1984.

15. For a fuller discussion of this subject see R. Garnaut and A. Clunies Ross, *Taxation of Mineral Rents* (Oxford: Clarendon Press, 1983), chapter 5.

16. O.C. Herfindahl, "The Value of Mineral Surveys to Economic Development," in *Resource Economics: Selected Works of Orvis C. Herfindahl*, ed. by D.M. Brooks (Baltimore: Johns Hopkins University Press, 1974).

17. For an illuminating discussion of the issues see A.D. Scott, "Who Should Get Natural Resource Revenues?" in *Natural Resource Revenues: A Test of Federalism*, ed. by A. Scott (Vancouver: University of British Columbia Press, 1975).

18. See J.P. Meekison, R.J. Romanow, and W.D. Moull, *Origins and Meaning of Section 92A: The 1982 Constitutional Amendment on*

Resources (Halifax: Institute for Research on Public Policy, 1985).

19. See A.M. Moore, "The Concept of a Nation and Entitlement to Economic Rents," in *Natural Resource Revenues*, ed. by Scott, pp. 240-45.

20. J.F. Helliwell, "Overlapping Federal and Provincial Claims on Mineral Revenues," in *Mineral Leasing as an Instrument of Public Policy*, ed. by M. Crommelin and A.R. Thompson (Vancouver: University of British Columbia Press, 1977), pp. 182-99.

21. For a review of this issue see K. Willett, "Mining Taxation Issues in the Australian Federal System," paper presented to the Workshop on Australia's Federal System, Resource Developments and Resource Trade, Australian National University, November 28-29, 1983.

22. P. Mieszkowski and E. Toder, "Taxation of Energy Resources," in *Fiscal Federalism and the Taxation of Natural Resources*, ed. by C.E. McLure and P. Mieszkowski (Lexington, Mass.: Lexington Books, 1983), pp. 65-92.

23. Willett, "Mining Taxation Issues," pp. 53-55.

24. Scott, "Who Should Get Natural Resource Revenues?," pp. 10-14.

25. R.A. Musgrave, "Who Should Tax, Where and What?" in *Tax Assignment in Federal Countries*, ed. by C.E. McLure (Canberra: Australian National University Press, 1983), pp. 2-19.

Chapter 3

Fiscal and Quasi-fiscal Arrangements Applied to Petroleum Exploitation

The prime purpose of this study is to conduct an empirical investigation into the working of the fiscal and quasi-fiscal devices applied to petroleum exploitation in a number of countries where this activity is of major importance. The countries selected are both developed and less developed. They all have arrangements whereby the investors in petroleum exploitation are private companies, sometimes in conjunction with state companies. Countries where the activity is wholly nationalized have not been considered, as the study seeks to examine the delicate relationship between governments and private companies. It follows that some of the main members of OPEC are excluded from the analysis, but two – Indonesia and Nigeria – are included. The study includes Canada and Australia, main examples of countries where two tiers of government have an interest in the revenues from petroleum exploitation. The types of fiscal arrangements in the selected countries vary greatly, and one of the objectives of the study is to test the comparative performance of structurally different schemes.

(1) Australia

In Australia the Crown owns all petroleum *in situ*. Onshore activities and those in coastal waters up to a three-mile limit are controlled by the governments of the different states and the Northern Territory and by the federal (commonwealth) government in the other territories. For offshore territories outside the three-mile limit, operations are essentially regulated by the Petroleum (Submerged Lands) acts of 1962 and 1980 passed by the commonwealth government. For offshore territories, exploration permits and the linked production licences are generally awarded on the basis of work-program bids; in cases where petroleum is known to exist a cash bonus or royalty, or a combination of these, may be employed. Royalty is generally at the rate of 10 per cent of the value of production. This can be increased to 12½ per cent if the licensee obtains a larger than normal area surrounding his discovery. The commonwealth government has the powers to reduce the royalty if it believes this would lead to the recovery of petroleum which would otherwise not be exploited. Revenues from royalties are shared between the commonwealth government and the adjacent state government in the ratio 60:40.

For onshore activities, powers relating to petroleum exploration and development are in the hands of state governments. They issue licences and determine the licence terms, the details of which vary from state to state. Royalties at the rate of 10 per cent of wellhead values are common,[1] while the small annual rental payments show some variation.

The commonwealth government levies several taxes on petroleum exploitation. There is a production levy or excise duty, whose rates vary according to the timing of the discovery and the date of issue of the production license. For "old" oil (i.e., from fields discovered before September 18, 1975) the rates have been as in Table 3.1. From July 1, 1984, the government introduced an excise on "new" oil (i.e., oil produced from discoveries made after 1975). The duty applies to onshore fields and offshore areas, with the proviso that for the offshore areas the production licence had to be issued prior to July 1, 1984. The schedule of rates is as in Table 3.2. On October 23, 1984, the government introduced a further change to the system. For fields discovered *before* September 18, 1975, but not developed by October 23, 1984, and which lie in offshore areas specifically excluded from the Resource Rent Tax (see below), an "intermediate" excise duty was introduced. The areas to which this duty applies include the Bass Strait, the North West Shelf, and Barrow Island. The schedule is as in Table 3.3.

Excise duties are expressed in relation to Bass Strait import-parity prices. These are periodically adjusted in accordance with international market conditions and exchange rates. The duty has been removed from crude oil from onshore producing areas in the period August 1, 1986, to June 30, 1987. The burden of the duty is borne by the domestic producer, and excise duties are deductible for corporate income-tax purposes. The commonwealth government also

Table 3.1
Rates of Excise Duty on "Old" Oil in Australia

Annual Production Range (thousands of barrels)	Marginal Excise Rate (%) July 1, 1983 - Aug. 30, 1986	Marginal Excise Rate (%) From Sept. 1, 1986
0 - 315	0	0
315 - 629	5	5
629 - 1,259	15	15
1,259 - 1,888	20	20
1,888 - 2,517	40	40
2,517 - 3,146	70	70
3,146 - 3,776	80	80
3,776 - 4,405	87	80
4,405 - 5,034	87	80
Over 5,034	87	80

Table 3.2
Rates of Excise Duty on "New" Oil in Australia

Annual Production Range (thousands of barrels)	Marginal Excise Rate (%)
0 - 315	0
315 - 629	0
629 - 1,259	0
1,259 - 1,888	0
1,888 - 2,517	0
2,517 - 3,146	0
3,146 - 3,776	10
3,776 - 4,405	20
4,405 - 5,034	30
Over 5,034	35

ruled that they are deductible for royalty purposes as well. State governments have been unhappy about this, as the consequence is a serious erosion in their tax base. The Queensland government has ruled that excise duties would not be deductible for its royalty.

Table 3.3
Rates of "Intermediate" Excise Duty on Oil in Australia

Annual Production Range (thousands of barrels)	Marginal Excise Rate (%)
0 - 315	0
315 - 629	0
629 - 1,259	0
1,259 - 1,888	0
1,888 - 2,517	15
2,517 - 3,146	30
3,146 - 3,776	50
3,776 - 4,405	55
4,405 - 5,034	55
Over 5,034	55

On July 1, 1984, the government proposed a new Resource Rent Tax (RRT). It applies only to "Greenfields" offshore projects, defined as projects for which production licences were issued after July 1, 1984. Specified areas excluded from the new tax include the Bass Strait, the North West Shelf, and Barrow Island, and in those areas the royalty and excise arrangements, as described above, apply. In areas where the RRT applies, the royalty and excise duties are abolished.

The RRT is levied on the net cash flows, before company income tax, of projects that have achieved a specified return. This return is 15 per cent plus the long-term bond rate (around 14 per cent in 1985). The total rate (which would have been around 29 per cent in 1985) is used to accumulate the pre-tax cash flows until a positive cumulative total has been attained, at which stage tax at the rate of 40 per cent is levied on the positive amount. All relevant exploration, development, and operating costs are allowed as immediate deductions, with any excess of expenditures over receipts at the end of a year being compounded forward at the threshold rate. Payments and receipts related to the financing of projects are excluded from the calculation. The government is considering the introduction of a system of cash bidding for the allocation of selected offshore acreage. In the event that this system is introduced, the government has decided that the bids would not be deductible for RRT purposes.

The RRT is assessed on a project basis, but "project" is defined to include the production-area licence as well as treatment and other facilities and operations outside that area which are necessary to the production of marketable petroleum. The base could thus include a number of proximate fields. Downstream activities are not, of course, included in the scope of the tax.

The RRT is deductible for income-tax purposes, although it is unusual for the RRT to be levied before normal company tax. The government felt that, because the RRT is levied on a project basis, the practical problems involved in calculating a hypothetical normal company tax would be too great.

In November 1985 and March 1986, agreements were made between the Western Australian and commonwealth governments to introduce a Resource Rent Royalty (RRR) on the Barrow Island oil field, to replace the state royalty and the commonwealth excise duty. The agreement incorporated revenue-sharing arrangements and the RRR was introduced retrospectively from July 1, 1985. The new tax is modelled on the RRT with the rate being 40 per cent. A significant difference is that the accumulation rate under the RRR is effectively left to be determined by an arbitrator, who has to have principal regard to the cost of capital in making his determination.

Company income tax is levied by the commonwealth government at a rate which is currently 46 per cent but is due to increase to 49 per cent from financial year 1987-1988. According to provisions (Division 10AAA) of the Australian Income Tax Assessment Act of 1936, the rate of write-off for development costs for "prescribed petroleum operations" is on a straight-line basis over 10 years or the life of the field, whichever is less. This applies to expenditure on wells, flow lines, separators, and platforms. It is also possible for investors to obtain write-offs under Section 124AG of the income tax act, which provides for depreciation of plant and machinery at a rate of 20 per cent on a straight-line basis. This rate would apply to producing wells. Drilling-plant and downhole equipment can be relieved at the rate of 33⅓ per cent. Capital expenditure on pipelines is deductible, under Division 10AAA of the act, on a straight-line basis over 10 years; this rate also applies to transportation by railway or road.

There are no ring-fence regulations in Australia. Thus, ongoing investors can apply allowances relating to new exploration and development activities against any existing income.

(2) United Kingdom

In the United Kingdom petroleum rights are vested in the government by the Petroleum (Production) Act of 1934, which was extended to the U.K. Continental Shelf by the Continental Shelf Act of 1964. The great bulk of petroleum exploitation activity is offshore. Licences to explore for and produce petroleum are awarded through periodic licence rounds, of which there have been 10 to date. Blocs have usually been awarded by a discretionary system, though a number have been awarded by competitive cash-bonus bidding. Under the discretionary system, bids are assessed against a number of criteria which emphasize the technical and financial competence of the applicants and their contribution to the U.K. economy. Over the years greater attention has been paid to such criteria as the balance of payments, the growth of industry and employment, and the promotion of research and development work in the United Kingdom.

Special taxation of petroleum exploitation in the United Kingdom dates to 1975, when the Oil Taxation Act was passed. This act ensured that three different taxes would be imposed on North Sea oil exploitation. The first was the traditional royalty which accrued to the state in the United Kingdom as landlord, the second was the Petroleum Revenue Tax, and the third was normal corporation tax.

The traditional royalty rate is 12½ per cent, but the effective royalty depends on the base to which the rate is applied. In the first four licensing rounds the base was gross revenues at the wellhead; this was calculated from landed values less transport and initial treatment costs. The U.K. Inland Revenue in practice allowed as deductions from the landed price not only transport costs from the fields in the North Sea but also around 70 per cent of production platform costs, representing necessary initial treatment costs. Given the magnitude of these costs, the effective royalty as a proportion of the landed price could be reduced significantly below 12½ per cent. From the Fifth Licensing Round onwards, the base for the royalty has been changed, becoming 12½ per cent of the landed price. In the 1983 budget a major concession was made to stimulate development of new fields: for fields for which development approval is given from April 1, 1982, the royalty is abolished; this concession does not apply to fields in the southern basin (which have all been found to be gas, to date) and to onshore activities.

The Oil Taxation Act of 1975 introduced the Petroleum Revenue Tax (PRT) as a special tax on profits from North Sea oil exploitation. This tax is levied on a field-by-field basis. The original rate of tax was 45 per cent, and the base was gross revenues minus the sum of a number of allowances. The allowances were accrued field losses, operating costs, royalties, 175 per cent of the main field capital costs, field-related exploration costs, and an oil allowance equal to the value of 10 million tons of oil (with no more than 1 million tons eligible for use as an allowance in any one year). Interest on loans was not allowed as a deduction, and as compensation for this the so-called "uplift" of 75 per cent of capital expenditure was introduced. The capital allowance deduction was allowed on a 100 per cent first-year basis.

The uplift and oil allowances were designed to give particular help to small and less profitable fields. Further help was provided by the safeguard and tapering (or annual limit) provisions. In broad terms these state that if gross profits in any year are less than 30 per cent of accumulated field investment, the PRT becomes zero; and the maximum PRT in any year is 80 per cent of the excess of gross profits over 30 per cent of field investment.

Since 1975 several changes have been made to the PRT. In the Finance (No. 2) Act of 1979 the rate of PRT was increased to 60 per cent as of January 1979. At the same time the uplift on capital expenditure was reduced from 75 per cent to 35 per cent and the oil allowance was reduced to 5 million tonnes, with no more than 0.5 million tonnes being allowed in any one year. As of November 1979, in the Petroleum Revenue Tax Act of 1980, the dates for payment of the PRT were advanced by two months. In the Finance Act of 1980, the rate of PRT was increased to 70 per cent as of January 1980.

Changes to some of the PRT allowances were introduced in the 1981 budget. From January 1981, the 35 per cent uplift on capital expenditure has been restricted to expenditure incurred up to the time when cumulative incomings from a field first exceed cumulative outgoings (field payback). For the purposes of this calculation, outgoings are defined to include any uplift on capital expenditure. Expenditure incurred after this cut-off period will not attract uplift.

The 1981 budget also saw changes to the safeguard and tapering provisions, introducing a restriction on the time period during which these concessions apply. The period is now half as long again as the time it takes for a field's payback to be achieved; the calculation is in terms of chargeable periods, each of which is six months, and outgoings are again defined to include any uplift on capital expenditure. Since eligibility for safeguard and tapering is calculated on a six-month chargeable period, instead of annually, from January 1, 1981, the maximum PRT payable in any period has thus become 80 per cent of the amount by which gross profits exceed 15 per cent of accumulated investment.

In the budget of 1981 the government also introduced a new tax, the Supplementary Petroleum Duty (SPD), with effect from January 1981. The rate of this duty was 20 per cent, with the base being gross revenues minus an annual allowance of one million tonnes. The duty, levied on a field-by-field basis and payable monthly, was deductible for PRT and corporation tax. After much protest by the oil companies, the Chancellor of the Exchequer announced in his budget of March 1982 that the SPD would be abolished from the beginning of 1983.

The announcement of the abolition of SPD was accompanied by the raising of the PRT to 75 per cent and by the introduction of advance PRT (APRT), also to take effect from January 1983. The APRT was to be levied in exactly the same way as the SPD, with a rate of 20 per cent and a base of gross revenues minus an allowance of one million tonnes per year. The tax would thus take effect from the first day of production. Payments could be credited against normal PRT; where no PRT was payable, or where liability was insufficient to absorb all APRT, excess APRT would be carried forward and set off against future PRT. APRT payments would be included as deductions in computing the payback period for a field. Liability to APRT would be removed after five years of payment of the tax. Repayment of any APRT which had not been fully set off against normal PRT would also be made after five years of liability rather than at the end of field life. In the budget of 1983 plans were announced to phase out the APRT. The rate was reduced to 15 per cent for the period July-December 1984, 10 per cent for 1985, and 5 per cent for 1986; the tax was abolished at the end of 1986.

In the 1983 budget further major PRT concessions were made. Up to 1983, exploration costs had to be accumulated and could be set against income only from the field to which the exploration related. Only if the exploration was clearly abortive could the costs be set against other income for PRT purposes. Since 1983 exploration costs can immediately be set against any other PRT income and are deductible on a 100 per cent first-year basis. In the 1983 budget the oil allowance for new fields was doubled to 10 million tonnes, with a maximum of 1 million tonnes being deductible in any one year. This concession does not apply to the southern North Sea gas fields or to onshore fields.

In the Finance Act of 1987, further PRT concessions were made for fields outside the southern sector. The investor now has the option of utilizing a new crossfield allowance, equal to 10 per cent of development costs prior to field payback and applicable immediately against PRT income from other fields. No uplift is available on the expenditure to which the allowance relates. A further concession permits research and development costs not related to a specific field to be deducted from any PRT income after a three-year period.

Normal corporation tax applies to petroleum exploitation. Since 1974 there has been a one-way ring fence established around petroleum exploitation. This means that losses and capital allowances emanating from outside the ring fence cannot be set against income arising within the ring fence. On the other hand, losses arising within the ring fence can be set against other, non-ring fence income.

The rate of corporation tax was 52 per cent from 1973 to April 5, 1983. For financial year 1983-1984 the rate was 50 per cent; for 1984-1985, 45 per cent; for 1985-1986, 40 per cent; from 1986-1987, 35 per cent. While the tax rates are being reduced, the rates of relief for investment in plant and machinery are also being reduced – from 100 per cent first-year basis up to March 14, 1984, when the rate became 75 per cent – to March 31, 1985, 50 per cent to March 31, 1986, and 25 per cent on a declining-balance basis thereafter. Relief for exploration and development drilling continues to be on a 100 per cent first-year basis. Losses, operating costs (including loan interest), royalties, and PRT are all allowable deductions, but the APRT is not an allowable deduction.

In this study the emphasis is on the operation of the fiscal system with regard to new investments. Accordingly, the system applicable to new fields has been incorporated in the detailed empirical work. This means that the provisions for royalty relief, the higher oil allowance for PRT, and the immediate relief for exploration costs are all included. Where immediate relief for exploration costs is taken by investors, the uplift benefit is forgone. This is the method that investors have preferred and so is included in this study.

Participation by the British National Oil Corporation (BNOC) has been a feature in some licences. For licences awarded under the first four rounds, participation was introduced retrospectively on a "voluntary" basis – BNOC was given the right to purchase 51 per cent of oil produced in the different fields. Thus, to quote from a famous speech of a government minister, Sir Harold (later Lord) Lever, at the time this was introduced in the mid-1970s, participation meant "no gain no loss" to the oil companies. Under the Fifth Round terms, BNOC was a compulsory equity partner, to the extent of 51 per cent, in all licences; it was also a full risk-sharing partner for both exploration and development costs, and so the arrangement is really a joint venture. Under the Sixth Round terms, BNOC's privileges were further increased – participation was on a carried-interest basis and the oil companies were asked to bid interests to BNOC of 51 per cent or more; exploration costs would be reimbursed only when a field was discovered and declared commercial. By the time the Seventh Round was announced (1980), there had been a change of government. The Conservative government removed BNOC's privileges, and BNOC had to compete for licences on the same basis as any other oil company, though it was still given the right to buy 51 per cent of all oil at market prices. In the Eighth Round the same arrangements as those of the Seventh prevailed. Since then the exploration and production interests of BNOC have been privatized in a new company, Britoil. BNOC continued to exist as an oil purchaser and trader to the extent of 51 per cent of production until 1985, when the corporation was abolished. The Oil and Pipelines Agency was set up to maintain the right to purchase participation oil but these rights are not being exercised. Thus, in the present study no government participation is included.

The government has one discretionary fiscal power which it can utilize to foster the development of marginal fields. The Department of Energy can remit royalties where it is convinced that the requirement to pay royalties is discouraging the development of a field or causing premature abandonment to be considered. The remission of such royalties is free of PRT and corporation tax (i.e., no additional PRT or corporation tax is payable, even though royalties are normally deductible items for these two taxes). To date several applications for remission of royalties have been made, but none has been granted.

(3) Norway

The exploration and development of offshore petroleum in Norway is governed by the Continental Shelf Act of 1963, the Royal Decree of 1972 (as amended), and the Petroleum Activities Law of 1985. In Norway mineral rights are vested in the Crown. Licensing is done by a discretionary system, the criteria including technical and financial competence, contribution to the Norwegian economy (in particular the balance of payments and industrial growth and development), exploration program offered, and government participation offered. There are three main taxes levied on petroleum exploitation, namely, royalty, income tax, and Special Tax.

As in the United Kingdom, the royalty is part of the licence. The base of the royalty is gross revenues at the production-area point of shipment. For licences awarded before December 1972, the rate is 10 per cent; for licences awarded since December 1972, a progressive schedule of royalty rates applies, as shown in Table 3.4. The rates apply to the *total* production from a field. The tax is thus applied on a slab basis, not an incremental one. The rules also state that when production from a field declines, the royalty rate will fall as well, according to the schedule, except that it may *not* fall below 12 per cent. On gas the royalty rate is fixed at 12½ per cent. Section 26 of the Royal Decree of December 1972 gives the government the power to fix lower royalty rates "if the sea depth, capacity per well, or other conditions so require," but to date there have been no reductions in royalty rates.

There are two income taxes payable by all companies operating in Norway – National Income Tax, at the rate of 27.8 per cent; and Municipal Tax, at the rate of 23 per cent. With regard to petroleum, the Municipal Tax is collected and utilized not by the local governments but centrally. In 1975 the Norwegian government introduced a tax package on North Sea operations which maintained the royalty provisions described above but substantially changed income taxation.

Table 3.4
Royalty Rates on Oil Production in Norway

Average Field Production (barrels per day)	Rate of Royalty (%)
Under 40,000	8
40,000 and under 100,000	10
100,000 and under 225,000	12
225,000 and under 350,000	14
350,000 and above	16

The 1975 act introduced allowances which apply equally to both income taxes. Deficits accumulated over the previous 25 years are deductible as losses, although there is a restriction on the rate at which such losses can be deducted. The deduction in any one year is limited to one third of the total deficit in the previous 15 years, so that the total deductions have to be distributed over a minimum of 3 years. Eligible costs include exploration costs, various licence fees, and royalties. Only 50 per cent of losses incurred from other (non-Continental Shelf) activities in Norway may be deducted from Shelf income. Had the 1975 act not stipulated this restriction, companies would have an incentive to invest in non-Shelf activities, and tax revenues from North Sea oil exploitation would be postponed. The provision means, in effect, that 50 per cent of non-Shelf operating losses may be set against Shelf income, as can 50 per cent of the costs of investing in, say, a refinery or marketing facilities. On the other hand there is no restriction on the ability to set losses incurred in Shelf operations against income from other activities in Norway. Thus, there are still advantages to be obtained from integrated operations in Norway. However, losses or deficits incurred abroad are not allowed as deductions against North Sea income in Norway.

The 1975 act also introduced special depreciation provisions for North Sea operations. The normal depreciation allowances were considered too restrictive for the size of the investments and risks incurred in the North Sea, and the additional or initial allowances available in existing income-tax legislation were not considered suitable. Accordingly, new provisions were introduced. These stated that deductions for capital expenditure incurred in production and transport facilities could be claimed to the extent of 16⅔ per cent per annum from the date at which the assets were brought into use. Thus, a six-year straight-line depreciation system was introduced, but it effectively commenced only when oil production started. This last qualification has been of considerable significance. It has meant that, when an enterprise was in receipt of income from a field in the North Sea and was in a tax-paying position, it could *not* immediately set depreciation allowances relating to a new field against the income from its existing operations; such offsetting was not allowed until production from the new field started. There is no ring fence around each field in Norway, but the way in which the depreciation allowances were given produced a rather similar effect.

The most widely publicized innovation in the 1975 act was the Special Tax, which applies only to offshore operations. The tax was introduced at the rate of 25 per cent. The base for this tax is the same as that for income tax, with important modifications. In addition to the depreciation and other allowances for income tax discussed above, there is a further special allowance. In the 1975 act the special allowance, in any one year, was equal to 10 per cent of the value of capital expenditure (at historic cost) on offshore activities brought into use over the preceding 15 years. Capital equipment includes investments in transport systems and related terminal facilities; exploration expenditure is not allowed as part of the special allowance. If production from a field lasted 15 years, the total value of the special allowance for that field would thus be 150 per cent of the value of capital expenditure. The special allowance does not come into effect until production from the field has actually started. This is important when the tax implications of a second field are being analyzed: the ability to utilize the special allowance from the capital expenditure on the second field against the income of the first field is restricted to the time when production commences on the second field. If a field's producing life is less than 15 years—and this is likely to be the case for many of the smaller fields—then, of course, the full allowance of 150 per cent of capital expenditure cannot be utilized. Such unutilized allowances from one field may, however, be carried over and used when calculating the tax base for Special Tax on a second field. This is because there is not, strictly speaking, a ring fence around each field for Special Tax purposes.

Special Tax is not deductible for income-tax purposes. In June 1980, the fiscal system in Norway was revised, with the changes mainly relating to the Special Tax. The rate was increased from 25 per cent to 35 per cent. In addition, the special allowance in any one year was reduced to $6\frac{2}{3}$ per cent of accumulated investment over the previous 15 years. It was made clear, however, that the equivalent of 100 per cent of capital costs would always be allowable over the life of a field even when strict application of the rule would not suggest eligibility for such a total; this was a concession to help short-lived fields. The 1980 rules stated, however, that utilization of the special allowance could not begin until one year after production starts. A further change stipulated that all losses would now be eligible for write-off whenever sufficient income becomes available. There was a change concerning the timing of payment of both income taxes and the Special Tax – before 1980 a lag of around 12 months occurred between the liability for these taxes and their actual payment; this lag has now been reduced to 6 months.

In the summer of 1986 major concessions were made to the fiscal system. From January 1, 1987, the rate of Special Tax was reduced to 30 per cent, and as of that date depreciation for both Special Tax and income tax commences from the time that the expenditure is incurred. Uplift is no longer available on capital expenditure after January 1987 but, as a transitional measure, uplift on past expenditure continues according to the old rules. For new fields (development approval since January 1, 1986) royalties are reduced to zero. Further, for Special Tax on new fields a volume allowance equal to 15 per cent of production is now available.

The fiscal position regarding dividend payments is complex, the distinction between National Income Tax and Municipal Tax being highly significant. When a company makes a distribution, the dividend payment is deductible from the National Income Tax but not from Municipal Tax, and dividend payments are not deductible for Special Tax. When a dividend is declared, Norwegian shareholders pay income tax on the dividend. When the distribution is made by a Norwegian subsidiary to its foreign parent, a special withholding tax is paid. The rate of withholding tax is determined by the double tax agreements between Norway and the foreign countries concerned; on subsidiaries of U.S. and U.K. companies the rate is currently 15 per cent.

In Norway joint-stock companies are obliged to maintain a reserve fund, whose minimum required amount is the higher of 20 per cent of the company's share capital or that amount which, when added to the share capital and revaluation fund, equals the company's debt. If the defined minimum has not been attained, then the company has to set aside funds according to the following rules:

1. Amounts equal to 10 per cent of annual profits, the latter defined as excluding any part of profits required to cover losses from previous years.
2. A further amount equal at least to any dividend declared by the company in excess of 10 per cent of the sum of the share capital, revaluation fund, and reserve fund at the beginning of the financial year.
3. Any share-subscription premium less the costs of establishing the company or increasing its capital.

Contributions to the reserve fund are, of course, made before payment of taxes. This reserve-fund legislation restricts the ability of a company to pay dividends.

Given the tax regulations and rates discussed above, it is important to clarify the dividends that can be paid. The maximum dividend payable may be calculated in the following manner (ignoring reserve-fund contributions and the capital tax, which is very small):

$$
\begin{aligned}
\text{Maximum Dividend (MD)} &= \text{Profit before tax (P) - Special Tax (ST) - National Income Tax (NIT) - Municipal Tax (MT)} \\
&= P - ST - 0.278\,(P - MD) - 0.23\,(P) \\
&= 0.492\,(P) - ST + 0.278(MD) \\
&= \frac{0.492\,(P) - ST}{0.722}
\end{aligned}
$$

When maximum dividend is paid, the various corporate taxes payable in 1987 are as follows:

$NIT = 0.278\,(P - MD)$

$MT = 0.23\,(P)$

Dividend Tax (DT) $= 0.15\,(MD)$
(for United States and United Kingdom)

$ST = 0.30\,(P - \text{Special Allowance})$

Oil companies operating on the Continental Shelf, like other enterprises on land, pay a further tax – the capital tax. For many years this was at the rate of 0.7 per cent of the value of net capital, but the rate has been progressively reduced in recent years and it is now 0.4 per cent. The base includes production, transport, and storage facilities; stocks of products produced; and securities and bank deposits. As far as offshore operations are concerned, the base does *not* include the value of crude oil in the reservoirs. The capital tax is not deductible for income-tax or Special Tax purposes.

Participation by the national oil company, Den Norske stats oljeselskap a.s. (Statoil), has taken place since the company was founded in 1972. In early participation schemes, some "net profit" agreements were concluded, but for some years now carried-interest agreements have been preferred. Statoil's interest is carried by the oil companies until a commercial discovery is made, at which point Statoil participates. In early agreements, Statoil agreed to pay its share of exploration costs. In most later agreements only development and operating costs were payable by Statoil, though in recent agreements with other Norwegian oil companies it has agreed to pay its share of exploration costs.

In early participation agreements there was a fixed, flat Statoil share. From the Third Licensing Round up to the Tenth Round participation agreements were concluded on a sliding-scale basis, which means that Statoil's share of *total* production increases with the size of peak production from the field. The procedure adopted is that Statoil's share is estimated at the time when a field is declared commercial; if the initial estimates prove accurate, then Statoil's interest would remain constant throughout the life of the licence; on the other hand, if estimated peak production is subsequently changed, Statoil's share would be retroactively altered. There might, of course, be several such retroactive adjustments.

The precise scales are the subject of negotiation between the oil companies and Statoil and are generally not published. A typical scale in the second half of the 1970s or early 1980s would give Statoil a minimum share of 50 per cent, increasing according to the schedule shown in Table 3.5. By the Seventh, Eighth, and Ninth Rounds the sliding scales had become truncated and the scale shown in Table 3.6 was reported as typical.

By 1983 there was growing concern about the enormous direct role that Statoil was playing in the whole economy. The Mellbye Committee was set up and eventually, in October 1984, new regulations regarding participation were introduced whereby the state took a direct share in new fields and Statoil was given a reduced role, as is illustrated in Table 3.7. The total government share was to remain unaffected.

By the time of the Tenth Round (1985-1986) oil prices were falling. In an attempt to retain investor interest, participation rates have been reduced. Under this round the total state share is in the 60 to 65 per cent range, with Statoil having a direct stake of 20 per cent on average. In the summer of 1986, a further concession was introduced – on new licences investors are no longer obligated to carry the state's share at the exploration stage.

Table 3.5
Statoil Participation – Typical Sliding Scale

Maximum Licence Producing Rate (thousands of barrels per day)	Statoil Working Interest (%)
0 - 75	50
75 - 100	52
100 - 125	54
125 - 150	56
150 - 170	58
170 - 190	60
190 - 200	61
200 - 210	62
210 - 230	63
230 - 250	64
250 - 270	65
270 - 290	66
290 - 310	67
310 - 330	68
330 - 350	69
350 - 370	70
370 - 390	72
390 - 410	74
410 - 430	76
430 - 450	78
450 and above	80

Table 3.6
Typical Statoil Participation, Recent Rounds

Peak Production (thousands of barrels per day)	Rate of Statoil Participation (%)
0 - 100	65
100 - 250	75
250 and above	80

Source: Norges Offentlige Utredninger, *Organiseringen av statens deltagelse i petroleumsvirksomheten* (Oslo: Universitetsforlaget, 1983), p. 42.

Table 3.7
Estimates of Likely Structure of Norwegian State Participation, Selected New Fields

Field	Direct State Share (%)	Statoil Share (%)
Sleipner	30	25.8
Oseberg	49.24	14
Troll 31/2	54	21
Troll (rest)	73	12
Gullfaks	73	12

(4) Indonesia

In Indonesia the basic legal framework for petroleum exploitation is contained in the Oil and Gas Law of 1960, Law No. 1 of 1967, the Foreign Investment Law, Law No. 11 of 1967, and Law No. 8 of 1971. Other relevant legislation is contained in presidential and ministerial decrees. The Oil and Gas Law of 1960 abolished the concession system. Law No. 8 of 1971 established the state company, Pertamina, and permitted it to enter into production-sharing agreements with foreign oil companies.

Indonesia has been the pioneer of production-sharing agreements whereby the oil companies are contractors to the state oil company. In the Indonesian agreements contractors pay both signature and production bonuses. The details of these vary from one contract to another with figures in the range $1 to $5 million being typical. Production bonuses vary with the level of production. This study has assumed bonuses of $5 million at 20,000 barrels per day (b/d), $10 million at 50,000 b/d, $20 million at 100,000 b/d, and $40 million at 200,000 b/d. Bonuses are not recoverable costs under the production-sharing scheme. They are deductible for income-tax purposes, but they are grossed up in order not to reduce the government take.

For cost-recovery purposes, under the production-sharing scheme, exploration costs and intangible drilling costs have been deductible as soon as income from the contract area in question permits. Tangible capital costs have been recoverable in the form of depreciation, which is allowed over one half of the depreciation life by the double-declining-balance method. The contractor has the option to switch to the straight-line method whenever it is advantageous. There is a one-time investment tax credit equal to 20 per cent of tangible development costs. The credit is deducted from gross production before production sharing takes place.

After cost recovery and investment tax credit, the remaining oil has usually been split 65.9091:34.0909 (on a per-tax basis) in favour of Pertamina; on a post-tax basis this has been equivalent to 85:15 in Indonesia's favour. There have been some divergences from this figure—for example, a major agreement with Caltex in late 1983 provided for an 88:12 split.

In Indonesia, contractors have been obliged to provide a certain amount of production for the domestic market on preferential terms. The maximum obligation has been 25 per cent of the contractor's pre-tax share. For the first five years of production from a contract area, the oil can be sold at full market value but after that a figure of only $0.20 per barrel can be charged. During 1986, as an incentive to investors, this domestic-market obligation was abolished for new agreements.

Contractors have to pay corporate income tax on their taxable profits. Operating costs, exploration costs, tangible drilling costs, and depreciation are all deductible in order to obtain taxable income. Until recently the corporate tax rate was 46 per cent. There is another tax, known as the Tax on Interest, Dividends and Royalties, which is payable regardless of whether dividends have been remitted or not. This is at the rate of 20 per cent of profits after corporation tax. There has thus been a combined tax payable of 56.8 per cent [0.46 + 0.2 (1 - 0.46)].

In 1984 the income tax in Indonesia was reformed.[2] The corporate rate was reduced to 35 percent, so the combined rate is thus 48 per cent. Depreciation terms were also changed; for many items of equipment employed in petroleum exploitation, rates of 25 per cent on a declining-balance basis are available with some items having rates of 10 per cent. Intangible drilling costs continue to be expensed. Although the new tax law took effect from January 1984 onwards, exploration agreements in 1984 and in 1985 were signed under the old terms.[3] The precise application of the new laws to petroleum contracts remains unclear. The government does not wish its total take to be decreased as a consequence of the change in income-tax rate. For the government's take to remain unchanged would imply a pre-tax oil-sharing split of 72:28 in Indonesia's favour. This ratio, as well as the 65.9091:34.0909 one, has been employed in the present study.

In Indonesia the rules require investors to set up separate companies for each contract area, and each company is assessed separately for income tax. The production-sharing arrangements are of curse also on a contract-area basis. It follows that there are no significant fiscal advantages from ongoing investment, although if more than one field were discovered in one contract area, there would be significant advantages when the second field was developed.

(5) Malaysia

Under the 1974 Petroleum Development Act, petroleum concessions in Malaysia were terminated and replaced by production-sharing agreements. The national oil company, Petronas, was established and given exclusive rights to explore for and produce petroleum and to negotiate production-sharing agreements with oil companies.

The current fiscal package in Malaysia consists of production-sharing arrangements as well as royalty, income tax, Export Tax, Excess Proceeds Tax, and contribution to a research fund. There are also a number of bonuses payable – signature bonuses, which have averaged around $1 million in recent years; discovery bonuses, which have been around $2.5 million per commercial discovery in recent years; and production bonuses. Bonuses are deductible items for income tax. For new contracts (signed after December 5, 1985), all bonuses have been eliminated.

While many past contracts have stipulated a ceiling of 20 per cent of gross production for cost-recovery purposes, recent ones have permitted 30 per cent. A major change was announced by the finance minister in December 1985, when he stated that 50 per cent of gross production for crude oil and 60 per cent for gas would be permitted in new contracts. Under the cost-recovery mechanism all costs can be recovered as fast as the ceiling permits, and unrecovered costs in any year are carried forward.

The profit oil split between Petronas and the investor has been 70:30 in favour of Petronas in many contracts, although in some the state company has been able to negotiate more favourable terms for Malaysia; in at least one contract, the contractor's share is as low as 20 per cent for production in excess of 32,000 kilolitres per day. In December 1985, the finance minister announced a profit oil split for new contracts more favourable to investors.[4] Details are in Table 3.8. These profit oil shares are applied only to the first 50 million barrels of cumulative production from a contract area; all production in excess of that figure is split 70:30 in favour of Petronas.

Table 3.8
Profit Oil Shares for New Contracts in Malaysia

Gross Production	Shares of Profit Oil (%)	
(barrels per day)	Petronas	Contractor
0 - 10,000	50	50
10,000 - 20,000	60	40
20,000 and above	70	30

Contractors have several other fiscal obligations. The royalty is levied at the rate of 10 per cent on a base price that equals the average value of Malaysian crudes at the time of the signing of the contract in question. This base price escalates at 5 per cent per year in money-of-the-day terms. There is an Export Tax at a rate of 25 per cent, based on the exports of a contractor from his share of profit oil. There is an Excess Proceeds Tax equal to 70 per cent of the excess of the world price over the base price. There is a research-fund contribution equal to 0.5 per cent from the sale of all the contractor's cost oil and profit oil; this is termed Payments to Research Fund.

Income tax is levied at the rate of 45 per cent on the contractor's profits. Depreciation of production platforms for purposes of this tax is at the rate of 10 per cent on a straight-line basis; other equipment is depreciated at 20 per cent on a straight-line basis; pre-production intangibles are expensed. There is also an initial investment allowance of 20 per cent. Royalties, bonus payments, the Export Tax, the Excess Proceeds Tax, and Research Fund payments are all deductible items.

As far as income tax is concerned, there is no ring fence in Malaysia and the investor can thus obtain the fiscal advantages from ongoing investment elsewhere. Production-sharing, however, is on a contract-area basis and the system announced in December 1985 means that, when a second field is discovered in a contract area where recoverable reserves of more than 50 million barrels already exist in the first field, the contractor will receive only 30 per cent of profit oil from the *whole* of the second field.

Participation with Petronas, as well as production sharing, is required in Malaysia. In recent years the rate has been 15 per cent on a carried-interest basis, and Petronas does not have to repay its share of exploration costs. After the new production-sharing terms were announced in December 1985, it became clear that participation at the rate of 50 per cent was required by the government.

(6) China

Although a few exploration agreements were signed between the Chinese authorities and foreign oil companies in 1980, it was not until 1982 that petroleum regulations were promulgated, the Chinese National Offshore Oil Corporation (CNOOC) was formed, and a round of competitive bidding was announced. In essence the 1982 regulations provide for production-sharing terms with CNOOC plus participation and taxes.

Awards were made in 1983 on the basis of a model contract, which gives CNOOC the exclusive right to explore for and produce petroleum in the Chinese Continental Shelf. Under the terms that were accepted by many companies, a lump-sum signature bonus of $1 million was payable. Exploration costs are fully borne by the contractors. CNOOC has the option to participate to the extent of 51 per cent when a discovery is made, and if it takes up the option it pays 51 per cent of development and operating costs. The first 17½ per cent of gross production is required for royalty (12½ per cent) and the Consolidated Industrial and Commercial Tax (5 per cent), which is payable in kind to the Chinese authorities through CNOOC. For cost-recovery purposes there is a ceiling of 50 per cent of gross production. Costs have to be recovered in a certain order—operating costs first, exploration costs second, and development costs third. An interesting feature is that unrecovered development costs can be carried forward with interest at 9 per cent.

Petroleum remaining after royalty and Consolidated Industrial and Commercial Tax and cost recovery is termed remainder or profit oil. This is split into "share" oil and "allocable" oil. Contractors have to bid the shares they are prepared to hand over to the Chinese (share oil); the remainder of the profit oil, the allocable oil, is split between CNOOC and the contractor according to their participating interests, which will be 51 per cent for CNOOC and 49 per cent for the investor if CNOOC exercises its rights. The percentages of production that investors agree to hand over to the Chinese in the form of profit oil varies from contract to contract. Table 3.9 illustrates a typical split in recent agreements; this is the split that has been assumed in the present study. The percentages shown in column 3 are generally known as the "x factors." CNOOC has the option to participate to the extent of 51 per cent of these quantities.

Table 3.9
Illustrative Profit Oil Shares for Recent Agreements in China

(1) Annual Gross Production (from Each Field) (thousands of metric tons)	(2) Share Oil (to Chinese Government)	(3) Allocable Oil (between Contractor and CNOOC)
Up to 500	30	70
500 - 1,000	35	65
1,000 - 2,000	40	60
2,000 - 3,000	45	55
3,000 - 5,000	50	50
5,000 - 7,500	56	44
7,500 - 10,000	68	32
10,000 and above	85	15

By 1985 exploration results were still rather disappointing, and the Chinese government felt it necessary to provide a stimulus to further exploration. Accordingly, reliefs were given for the development of smaller fields: when a production profile has been agreed with CNOOC and when the resulting annual peak production is anticipated to be below 1 million tonnes, the Chinese forfeit their claims to share oil; if peak production does turn out to exceed 1 million tonnes, then a retroactive adjustment is made. For fields with a peak production below 1 million tonnes per year, a royalty concession is also available. However, though no royalty is then payable, liability to the Industrial and Commercial Tax remains (5 per cent).

In China there is an income tax, which has rates graduated with taxable income. For petroleum operations, the great bulk of liability is at the top rate. The progressive element is the national income tax and there is a 10 per cent local supplement. Details are provided in Table 3.10. For the purposes of calculating taxable income, exploration costs are expensed and operating costs, royalty, and Industrial and Commercial Tax are deductible items. Depreciation of investment costs is on a six-year straight-line basis.

Table 3.10
Combined Income-Tax Rates in China

Taxable Income (in US$)	Combined Tax Rate (%)
0 - 142,857	30
142,857 - 285,714	35
285,714 - 428,571	40
428,571 - 571,429	45
571,429 and above	50

As far as application of the "x-factors" is concerned, there is a ring fence around each field. For cost-recovery purposes there is a ring fence around each contract area. For income-tax purposes there is no ring fence provision in the sense that all offshore activities in China can be undertaken by the same company.

(7) Egypt

In Egypt the basic laws governing petroleum exploitation are Law No. 86 of 1956 and Law No. 66 of 1983. Under these laws the Egyptian government, through the Ministry of Petroleum and the Egyptian General Petroleum Company (EGPC), negotiates production-sharing agreements with oil companies.[5] Signature and production bonuses are common. In 1984 signature bonuses ranged from $1 million to $6.1 million; a figure of $5 million has been employed in this study. Production bonuses vary according to the level of output achieved. In agreements signed in 1984 the amounts were in the range $2 to $5 million at 50,000 b/d; $4 million to $8 million at 100,000 b/d; and $6 million to $10 million at 150,000 b/d. In the present study figures of $2 million, $4 million, and $6 million, respectively, have been employed for these different levels of production.

Ceilings are placed on the amounts of crude oil eligible for cost-recovery purposes. These ceilings have ranged from 30 to 40 per cent in recent years; a figure of 30 per cent has been employed in the present study. Operating costs are recoverable in the year they are incurred. Exploration costs are recoverable at varying rates, between 20 and 25 per cent in recent contracts. The rate at which development costs are recoverable has ranged from 12½ to 20 per cent. In many contracts it is noteworthy that, if actual costs incurred do not consume the entire cost-recovery allowance, the excess cost oil accrues to the government and is not split as profit oil; this is akin to a 100 per cent marginal rate of tax on such output.

The profit oil split varies from one contract to another. The contracts signed in 1984 involved incremental scales, whereby Egypt's share of profit oil started at 80 per cent, in some cases rising in steps to marginal rates of 88 per cent when production attained 100,000 b/d. In the current study, the government share has been taken as 80 per cent for the first 90,000 b/d of profit oil, 83 per cent in the range 90,000 to 140,000 b/d, and 85 per cent for production in excess of 140,000 b/d.

In late 1986 the Egyptian government released details of new production-sharing terms. Two options are now available. The first is the more conventional and establishes the following tranches of production, measured in thousands of barrels per day:

Less than 25
25 - 50
50 - 75
75 - 100
100 and above

Within each division, the shares of production accruing to the two parties are determined by the bids made by the contractor and by subsequent negotiation between the two parties. These shares are not published.

In the second option the production shares are based on the price of oil and the level of investment and income. For each contract area the ratio (R) of accumulated revenue to accumulated expenses is calculated. (The latter term refers to the accumulated expenditure of the contractor in the contract area in question.) The production shares between the two parties are determined by the size of the calculated R factor, yielding tranches based on the R factors, as follows;

Less than 1.0
1.0 - 1.5
1.5 - 2.0
2.0 - 2.5
2.5 - 3.0
3.0 and above

The regulations stipulate a minimum share of 50 per cent accruing to EGPC; this is the share for R factors less than unity. The shares in the other tranches are determined by the contractors' bids and subsequent negotiation.

Under the new terms, exploration and development costs are recoverable at the rate of 20 per cent per year. The contractor recovers these costs out of a maximum of 40 per cent of production for offshore blocs and 30 per cent for onshore blocs. Signature and production bonuses will in future be paid in three installments, namely, at the effective date of the agreement, at the start of the second exploration phase, and at the start of the third exploration phase. Under the first option, production bonuses are paid when production attains the various tranche levels listed above. Under the second option, the bonuses are related to the R-factor tranches listed above.

To date there is no public knowledge of any actual terms agreed under the new scheme. Accordingly, the empirical work in this study is based on the arrangements that applied to agreements prior to the end of 1986. Investors in petroleum exploitation in Egypt generally do not themselves pay royalties and income tax. In many contracts EGPC pays on their behalf. This is, of course, taken into account in the determination of the production-sharing terms.

(8) Nigeria

In Nigeria there is a concession system dominated by the Nigerian National Petroleum Corporation (NNPC), which was established by Decree No. 33 of 1977 to replace the Nigerian National Oil Corporation, which in turn had been established in 1971. The NNPC has a major share in all new concessions. The fiscal system has been based on a package incorporating posted prices with royalty, profits tax, state participation and, until 1982, a domestic-market obligation at "low" prices.

The system of posted prices has been important primarily because it determines the base for royalty and income tax. The posted prices for crude oil are not directly calculated in relation to free-market realizations for the oil but rather, since 1979, have been based on notional values for production costs and profit margins. In 1979 the Nigerian authorities set notional costs at $1.10 per barrel and set the contractor's margin at $0.80 per barrel. Since that time the allowance for production costs has increased, first to $1.60 per barrel in July 1982 and then to $2.00 in February 1983; the profit margin became $1.60 in July 1982 and $2.00 in February 1983. The posted price is determined according to the following formula:

$$\text{Posted price} = \frac{\text{Official sales price} - (\text{Profit margin} + 15\%\ \text{of technical costs})}{0.88}$$

where the official sales price is the price that NNPC receives on contract sales.

The royalty is based on the posted price. Rates vary according to whether production is onshore or offshore and, if offshore, according to water depth. The rates since 1977 are 20 per cent for onshore production, 18½ per cent for production in water depths up to 100 metres, and 16⅔ per cent for production in water depths exceeding that figure.

The Petroleum Profits Tax is levied on values determined by the posted price minus the sum of the royalty and the notional production-cost allowance. The rate has been 85 per cent since 1979. The system of allowances permits expenditure on exploration and the first two appraisal wells to be expensed. All intangible drilling costs for appraisal or development purposes may also be expensed. For tangible capital expenditure, depreciation is on a five-year straight-line basis, but 1 per cent of the initial cost of such assets has to be retained by the licensee until the government authorizes disposal. There is an investment tax credit related to tangible capital expenditure. The rates are 5 per cent for onshore operations, 10 per cent for offshore operations in water depths up to 100 metres, 15 per cent for depths between 100 and 200 metres, and 20 per cent for depths exceeding 200 metres.

The domestic-market obligations required licensees to contribute a share of Nigerian domestic requirements at a price below the posted price. Each company's required contribution was relative to its proportionate share of total production in Nigeria. For such sales the licensees paid royalties on a posted price of $1.97 per barrel, even though the companies actually received a base price of $1.81 per barrel. In addition, Petroleum Profits Tax at the rate of 65¾ per cent has been payable on these domestic sales. In determining taxable income for this purpose, each company's proportionate share of allowable costs on such domestic sales was deductible. The domestic-market obligation was abolished in 1982.

Throughout the 1970s the effective participation of the NNPC was increased. By 1974 the rate of participation was generally 55 per cent; in 1979 it had increased to 60 per cent. The regulations concerning participation state that NNPC will pay its share of development costs as they are incurred. As far as exploration costs are concerned, NNPC's share is carried by the oil companies but is repaid over a period of three years once a field has been declared commercial. No interest is allowed on these carried costs. As part of many of the participation agreements, buy-back arrangements were concluded, whereby the companies bought back substantial quantities of oil from the NNPC.

By late 1985 Nigeria was having difficulty in attracting investment and proposed revised fiscal terms. These involve a number of steps. First, the government take (royalty plus Petroleum Profits Tax) is calculated using official sales prices rather than posted prices. Next, a revised government take is calculated according to the following formula:

$$\text{Revised Government Take} = OP - 0.85\,(TC) - ITC$$

where OP = Offset Price = $B \times RP$

RP = realizable price for oil based on market values

$B = K[(1 - r)\,0.85 + r]$

K = 1.0227 or whatever is prescribed by the minister of petroleum resources

r = royalty rate

TC = annual operating costs and depreciation under the Petroleum Profits Act of 1959, as amended

ITC = investment tax credit under the Petroleum Profits Act

Finally, the amount by which the initially calculated government take exceeds the revised government take is offset against the Petroleum Profits Tax as a credit.

Under the 1985 terms the equity profit margin of $2 per barrel was effectively protected if the state sales price became out of line with the free-market price. This protection in effect continued under netback pricing. In early 1987 netback pricing in Nigeria effectively came to an end. This, together with the utilization of official prices, seriously threatened a reduction in investors' profit margins. In February 1987 the Nigerian government proposed that the tax and royalty take on the investors' equity production would, at the government's discretion, be reduced when market prices fell below official prices so as to keep the equity margin positive. However, the companies apparently have to bear up to 10 per cent of any price fall below official levels.

Under agreements signed in early 1986, the producing companies could be required to increase the NNPC's share of production. The companies were allowed a margin of 50 per cent of the notional profit margin ($1 per barrel) on such sales. If spot prices fall this margin could readily disappear. This possibility lies behind the worries of the oil companies and the Nigerian government's new fiscal assurances.

(9) United States

Outer Continental Shelf

In the U.S. Outer Continental Shelf (OCS), mineral rights are vested in the federal government and thus only federal government legislation applies; state governments have no jurisdiction. Much of the original leasing legislation regulating offshore oil exploitation in the United States is contained in the Outer Continental Shelf Lands Act of 1953. Under this act, leases were awarded on the basis of sealed bids, which could offer either a cash bonus with a fixed royalty or a pure royalty bid. From 1954 to 1977, inclusive, the secretary of the interior elected to require cash-bonus bids for 98.8 per cent of the 3,162 OCS tracts leased. In 1978 the OCS Lands Act Amendments specified eight alternative bidding systems and authorized any combinations of these alternatives in addition to any other system that might occur to the secretary of the interior. The specified bidding systems and the constraints placed upon them are shown in Table 3.11.

The legislation allows four bid variables, namely, (1) cash bonus, (2) royalty, (3) net profit share, and (4) work commitment. Each of these may be paired with one or two of five different factors which are fixed at the time that bidding takes place. These possible fixed factors are seen to be (1) a fixed royalty of at least 12½ per cent, (2) a sliding scale royalty of at least 12½ per cent, (3) a fixed net profits share of at least 30 per cent, (4) a specified exploration program expressed in money terms, and (5) a fixed cash bonus.

The Department of the Interior has employed most combinations of leasing shown in Table 3.11. For a time there was some emphasis on bonus bids plus a fixed but sliding-scale royalty. This sliding-scale royalty, designed to ensure that higher royalty rates were levied on larger fields with higher production rates, was introduced by the Department of the Interior to increase competition for leases through the lower level of bonus bids induced by the sliding-scale royalty. It

Table 3.11
Alternative Bidding Systems for Leases, U.S. Outer Continental Shelf Under OCS Lands Act Amendments, 1978

	Bid Variable	Fixed Item(s)
1.	Cash bonus	Fixed royalty of at least 12½%.
2.	Cash bonus	Sliding-scale royalty of at least 12½% at beginning of lease period.
3.	Cash bonus	Fixed share of net profit of at least 30%.
4.	Cash bonus	Both (a) fixed royalty of at least 12½%, and (b) fixed share of net profit of at least 30%.
5.	Royalty	Either (a) specified work commitment based on dollar amount for exploration, or (b) fixed cash bonus, or (c) both.
6.	Net profit share	Fixed cash bonus.
7.	Work commitment based on dollar amount for exploration	Both (a) fixed cash bonus, and (b) specified sliding-scale royalty of at least 12½%.
8.	Work commitment based on dollar amount for exploration	Both (a) fixed cash bonus, and (b) fixed royalty.
9.	Any other combination of alternatives listed in points 1-8 above.	
10.	Any other system of bid variables, terms, and conditions as determined by the Secretary of the Interior, except that no such bidding system shall have more than one bid variable. Subject to veto by either the Senate or House of Representatives.	

Source: Outer Continental Shelf Lands Act Amendments of 1978, Pub. L. No. 95-372, 95 Stat. 629, 205.

was also thought that a sliding-scale royalty would be an improvement on a system of royalty bidding that could lead to such high levels of royalties that production became uneconomic.

The Department of the Interior expected exploitation costs in the Beaufort Sea area to be higher than in other OCS territories where it was effecting lease sales, and the formula for the Beaufort Sea sliding-scale royalty was slightly different from that employed elsewhere. In some leases the sliding scale employed was linear in form. However, the Department of the Interior found that, although this was easier to design, it could produce distortions; in particular there was a worry that at certain levels of production a linear schedule would cause erratic fluctuations in the royalty charged on increments to output, and that this could give incentives to producers to adjust their production to minimize the impact of royalty payments. A further problem with a linear form of sliding scale was that very high marginal rates could be attained even though average rates were comparatively low. The department also took the view that production costs were non-linear in form and that the royalty rate should more closely conform to the functional form of these costs in order to minimize the possibility of production losses.

The department therefore proposed a logarithmic sliding-scale royalty. The specific values of the constants in the formulae employed have varied from one location to another. The formula used for the lease sales in the Beaufort Sea in December 1979 was:

$$R_j = b\,[\,\ln(V_j/s)\,]$$

where R_j = percentage rate of royalty due on the unadjusted value of oil produced in quarter j

b = 10 (It is known that the value of b has been 8 in other cases.)

ln = natural logarithm

V_j = value of production in quarter j, adjusted for inflation, in millions of dollars

s = 2.5

To obtain the adjusted value of production, the actual value is divided by the inflation adjustment factor, which is a ratio given by the GNP fixed weighted price index for the quarter preceding the quarter of production divided by the value of that index for the quarter preceding the issue of the lease. The formula operates such that when the quarterly value of production, adjusted for inflation, is less than or equal to $13.23629 million, a royalty of 16⅔ per cent is payable on the unadjusted value of production. When the adjusted quarterly value of production is equal to or greater than $1662.845083 million, a royalty of 65 per cent is due on the unadjusted quarterly value of production; this is the maximum possible rate. In this study, a royalty rate of 16⅔ per cent is employed.

Lease-holders in the U.S. OCS are subject to Windfall Profits Tax, but Newly Discovered Oil in Alaska (including offshore) is exempt from the tax. Newly Discovered Oil is defined as oil found in 1979 or later. The legislation states that Newly Discovered Oil produced north of the Arctic Circle is exempt, as is any oil produced from a well located north of the Alaskan-Aleutian mountain range and more than 75 miles from the main Alaska pipeline.

The Windfall Profits Tax took effect from March 1, 1980. Although it is called a tax on profits, it is really a temporary excise or severance tax on all production of domestic crude oil. The amount of tax payable varies, depending on the classification of the oil. Taxable crude oil is categorized into three tiers. Tier One oil is the residuary classification, referring to crude oil produced from a property that began production prior to 1979, unless it qualifies for an exemption. The tax rate on Tier One oil is 70 per cent, the highest rate imposed under the Windfall Profits Tax Act. Independent producers are entitled to a 50 per cent rate on a limited quantity of Tier One production (see below).

Tier Two oil is taxable oil produced from stripper wells and oil produced from the National Petroleum Reserve. Stripper oil is defined with reference to production rates, where average well production is 10 or fewer barrels per day. Stripper oil prices were deregulated in 1976 and so the phase-out of price controls has less effect on the potential windfall profit arising from stripper oil than from Tier One oil. The tax rate on Tier Two oil is 60 per cent but independent producers are entitled to a lower rate, 30 per cent, on some Tier Two production (see below).

Tier Three oil is defined as Newly Discovered Oil, heavy oil, and incremental tertiary oil. Heavy oil is defined as oil with an average gravity of 16.0 degrees or less API. The rate of tax on Tier Three oil is 30 per cent.

As discussed above, oil from Alaska is exempt. The Prudhoe Bay field is taxable under Tier One, but the Kuparuk field is exempt. Oil produced by state and local governments and by medical or educational charities is exempt, as is oil produced by Indian tribes as well as front-end tertiary oil. The latter refers to oil that the Department of Energy has deregulated under the August 1979 energy regulations to finance a tertiary recovery project.

Under the act, independent producers are allowed reduced tax rates on as much of their combined production of Tier One and Tier Two oil as does not exceed 1,000 barrels a day. If an independent producer's daily production of Tier One and Tier Two oil exceeds 1,000 barrels, the reduced rates apply ratably to each of these categories of oil (but not in excess of a total of 1,000 barrels a day). For Tier One oil the special rate is 50 per cent (as opposed to the full rate of 70 per cent); for Tier Two oil the rate is 30 per cent (rather than 60 per cent). These reduced rates apply only with respect to working interests that were held on January 1, 1980, and do not apply to integrated oil companies or to owners of royalty or similar interests.

The amount of windfall profit generated by a barrel of oil is the amount by which the sales price exceeds the adjusted base price. The Tier One base price is the May 1979 ceiling price for Upper Tier oil, as determined by the regulations at that time, reduced by $0.21 per barrel. The Tier Two base price is determined by a method designed to approximate the price at which such oil would have been sold in December 1979 if all domestic crude were uncontrolled and the removal price for all domestic crude was $15.20; the actual value in any one case thus depends upon the quality and location of the deposits. In the case of Tier Three oil the procedure is the same but with the removal price for crude oil assumed to be $16.55 in December 1979. All base prices are adjusted for inflation from June 1979, but in the case of Tier Three oil there is an additional adjustment of 2 per cent per year.

The Windfall Profits Tax is levied on owners of economic interests in oil as defined for Federal Income Tax. It is thus applicable to owners of a working interest, royalty interest, and overriding royalty interest. State severance taxes are taken into account in determining the windfall profit when the severance tax rate does not exceed 15 per cent. The adjustment is the amount by which the state severance tax exceeds the severance tax that would have been imposed if the oil had been sold at its adjusted base price. Increases in the rate of state severance tax after March 31, 1979, are taken into account only if the increase applies equally to the entire price of the oil, and only to the extent that the total rate of severance tax does not exceed 15 per cent. Thus, if a barrel of Tier One oil is sold for $30 at a time when the adjusted base price is $20 and the state concerned levies a 10 per cent severance tax, the severance-tax adjustment would be $1 and Windfall Profits Tax at 70 per cent would be $6.30. On OCS territory, states cannot legally levy severance or any other taxes at present, despite the attempts of Louisiana to do so.

There is a net-income limitation on the amount of windfall profit from any one barrel. This limitation is 90 per cent of the net income attributable to that barrel, where net attributable income is defined as Taxable income attributable to taxable crude oil/Barrels of taxable crude oil produced. For purposes of net-income limitation, taxable income is computed in a manner similar to the method used to determine percentage depletion (see below). The following deductions are *not* permitted: percentage depletion; intangible drilling and development costs; Windfall Profits Tax; and qualifying tertiary injectoral expenses capitalized for the purpose of net-income limitation. Taxable income may be reduced by allowable cost depletion.

The Windfall Profits Tax is a deductible business expense for federal income-tax purposes. For purposes of calculating percentage depletion, gross income from the property is not reduced by the windfall profit. The Windfall Profits Tax is temporary and will be phased out over a 33-month period beginning no earlier than January 1988 and no later than January 1991. The timing of the phase-out depends upon the net revenue generated. If net revenue equals $227.3 billion by December 1987, the phase-out begins in January 1988; if this figure has not been reached by then, phase-out will start in the month following the month in which that total has been achieved; but phase-out will in any case begin in January 1991, at the latest.

In the Economic Recovery Tax Act of 1981, various changes were made to the Windfall Profits Tax. Stripper oil produced by independents after 1982 was made exempt. The act also provided for a $2,500 credit against the 1981 liability of a qualified royalty-holder. For 1982 this credit was replaced by an exemption of two barrels per day, rising to three barrels per day for 1985. The rate of Windfall Profits Tax on Tier Three crude was reduced to 27½ per cent for 1982, 25 per cent for 1983, 22½ per cent for 1984, 20 per cent for 1985, and 15 per cent for 1986 and thereafter. In the Deficit Reduction Act of 1984 the rates were set at 22½ per cent for the period 1984-1987, 20 per cent for 1988, and 15 per cent for 1989 and thereafter. These are the rates that have been employed in the empirical work of this study.

Offshore operators are liable for federal income tax on their activities. For many years the basic corporate rate was 46 per cent, with lower rates for "low" levels of taxable income. In October 1986 the Tax Reform Act was passed. This reduced the basic rate to 40 per cent for 1987 and 34 per cent thereafter.

For many years there was an investment tax credit in the legislation, which provided a dollar-for-dollar reduction of tax payable, up to an amount equal to 10 per cent of the purchase price of certain items of capital expenditure, including assets employed in petroleum exploitation. The Tax Reform Act of 1986 repealed the investment tax credit retroactively to January 1986. The transition provisions generally do not apply to petroleum lease and well equipment.

The Federal Income Tax is levied on gross income minus deductible items. The general rules permit reasonable allowances for the depreciation of property and for the production of income, where property means tangible real property not including land. Investment in intangible property with an ascertainable life generally has to be amortized.

The Economic Recovery Tax Act of 1981 introduced the Accelerated Cost Recovery System (ACRS), which was designed to promote investment by offering a rapid recovery of capital investment. For many assets employed in petroleum exploration and production, the time period was five years. The 1986 tax reform act generally increased the time period over which the cost of assets may be recovered. For assets employed in exploration and production by integrated companies, the recovery period is generally seven years, though for some assets a five-year period applies. The rate of depreciation is double declining balance, switching to straight line when that method produces a greater deduction.

Intangible drilling and development costs incurred by integrated oil companies may be expensed to the extent of 70 per cent under the 1986 act, with the other 30 per cent being capitalized and amortized over a three-year period. These provisions are less generous than under the previous legislation. For independent producers, domestic intangible and development drilling costs are fully deductible. Such costs include all expenditures made for wages, fuel, repairs, hauling, supplies, and other items without salvage value, incidental to and necessary for the production of oil and gas. If the election is not made to expense intangible drilling and development costs as incurred, such expenditures must be capitalized and recovered through depletion deductions.

Owners of economic interests in oil properties are entitled to depletion allowances on the income derived from the sale of oil from their properties. The original thinking behind the deduction was that it would be a form of compensation for the taxpayer's capital diminution brought about by the process of production. There are two methods of computing the depletion allowance for tax purposes: cost depletion and percentage depletion. The allowable deduction in any one year is the greater of cost depletion or percentage depletion. Since 1975, however, percentage depletion has been available only to certain taxpayers, in limited quantities.

As of January 1975, the percentage depletion was repealed for all domestic and foreign oil production with limited exceptions. It continues to be available for a certain part of crude oil production for companies which are *not* engaged in retailing or large-scale refining of petroleum products. For 1980 and subsequent years, the depletable quantity is 1,000 barrels. In 1984 the percentage rate of allowance was fixed at 15 per cent of the taxpayer's gross income from a property, a reduction from the previous rate. Allowable percentage depletion cannot exceed 50 per cent of the taxpayer's taxable income from the property computed without the depletion allowance; it may also not exceed 65 per cent of the taxpayer's taxable income for the year.

Cost depletion relates the recovery of the taxpayer's investment in an oil property to the proportion that the number of units of production sold during the taxable year bear to the total estimated units of production to be sold from the property throughout its life. The allowance in any one year may be expressed as:

$$\text{Costs} \times \frac{\text{Production for year}}{\text{Reserves}}$$

The cost of the economic interest is mainly lease-acquisition costs, but exploration costs could also be capitalized and recovered through depletion if they are not expensed. The estimate of recoverable reserves used in the calculation should include probable or prospective reserves as well as proven. It is possible for the allowances to be calculated with reference to gross revenues rather than barrels of production.

State governments levy taxes on oil exploitation. These can take the form of income tax, severance tax, or franchise tax on capital employed. Such taxes are all deductible in computing liability for Federal Income Tax. The Windfall Profits Tax is also a deductible item.

There are no ring-fence regulations in the United States. A company may be able to benefit from the fiscal advantages of ongoing investment. However, depreciation provisions relating to tangible items of capital expenditure can be utilized only when the asset is ready for use.

Alaska

In Alaska the state government is the landlord over a large part of the total territory. Consequently, the Alaskan government levies royalties on petroleum production. In the early days of exploitation, the conventional royalty at the rate of 12½ per cent of the wellhead value was imposed; this royalty applies to output from Prudhoe Ray, for example. In more recent lease sales the Alaskan government has experimented with other arrangements. This study examines a case of a royalty at 16⅔ per cent as this rate has been common in recent leases.

There is an Oil and Gas Properties Production Tax in Alaska. It was introduced in 1955 but has undergone many changes since that time, when it was a simple 1 per cent of the value of oil and gas produced. In 1970 a "stair-stepped" rate structure was established for oil, based on the productivity of individual wells—on the first 300 b/d a rate of 3 per cent was levied; on the next 700 b/d, a rate of 5 per cent; on the next 1,500 b/d, a rate of 6 per cent; and on production exceeding 2,500 b/d, a rate of 8 per cent. In 1972 a further modification was introduced by way of a cents-per-barrel tax, an alternative form of the production tax. It was "stair-stepped" to correspond to the "stair steps" of the percentage tax. Thus, on the first 300 b/d, 45.8 cents per barrel were levied; on the next 700 b/d, 51.1 cents; on the next 1,500 b/d, 53.8 cents; and for production exceeding 2,500 b/d, 59.1 cents per barrel. For production commencing on July 1, 1980, a 5.7 per cent reduction in the cents-per-barrel rates was to take place. Various amendments were introduced to both elements of the production tax following litigation by oil companies. In 1973 the "stair steps" and tax rates were changed such that the first 300 barrels per day were taxed at 5 per cent or 16.875 cents per barrel; the next 700 b/d at 6 per cent or 20.25 cents per barrel; and everything above 1,000 b/d at 8 per cent or 27 cents per barrel. The tax payable was the higher of the two calculations. The cents-per-barrel tax varies every month with an escalator based on the Wholesale Price Index for crude oil. In calculating the tax, the state's royalty is exempt and pro-rated among the three "stair steps"; thus, for any month the production in each step is multiplied by 0.875 (where the royalty rate is 12½ per cent).

In July 1977, the production tax was fixed at a flat rate. The percentage-of-value rate was increased to 12½ per cent; the cents-per-barrel amount was made equal to 60 cents per barrel of taxable old crude oil and 80 cents per barrel for all other taxable oil. The current level for all oil is now 80 cents per barrel. The production tax payable is the greater of the percentage-of-value or cents-per-barrel calculations multiplied by the economic-limit factor determined for oil production from the lease in question. For old crude oil the economic-limit factor equals

$$1 - \frac{\text{PEL}}{\text{TP}}$$

and for all other oil the economic-limit factor equals

$$\left(1 - \frac{\text{PEL}}{\text{TP}}\right)^{\left(\frac{460 \times \text{WD}}{\text{PEL}}\right)}$$

where PEL = production per month at the economic limit
TP = total production during the month for which tax is payable.
WD = number of well days in that month

The production rate at the economic limit is based upon a calculation of the relationship between, on the one hand, the value of imported crude oil at a West Coast refinery minus the cost of transport to the point of production in Alaska and, on the other hand, the average direct monthly operating costs for producing the oil. The monthly production rate at the economic limit is presumed to be 300 barrels times the number of well days for the month for which tax is to be paid. The taxpayer can rebut this presumption by providing evidence of a different production rate at the economic limit. The presumed monthly production rate at the economic limit of 300 b/d includes royalty interests.

Further changes were made to the production tax with effect from July 1, 1981. On fields that were in production before June 30, 1981, the rate of percentage-of-value tax was kept at 12½ per cent for the first five years after commercial production commenced, becoming 15 per cent thereafter. Amendments were also made to the regulations for calculating the economic-limit factor. The formula as described above was retained, but, during the first 10 years of field production, the economic-limit factor would be applied as calculated only if it was computed at 0.7 or less; if the computed figure exceeded 0.7 the economic-limit factor to be applied would be 1.0. After the first 10 years the maximum economic-limit factor would be 0.7.

Since 1973 there has been a second type of oil-production tax, known as the Oil and Gas Regulation and Conservation tax. It is imposed only on oil production. It is at the rate of one eighth of one cent per barrel. As with the main production tax, production attributable to a royalty interest of the State of Alaska or the U.S. government is not taxed. The payment of this tax is made in the same way as the production tax.

Since 1973 there has also been a special Oil and Gas Exploration, Production and Pipeline Transportation Property Tax levied in Alaska. It is a levy at the rate of 20 mills on certain items of oil and gas hardware throughout the state. The eligible properties include exploration properties such as seismic equipment and drilling rigs; production properties such as wells, platforms, and field gathering lines; and pipeline transportation properties such as pipelines, pump stations, and integrated terminal facilities. Oil and gas refining and processing properties, retail distribution outlets, and oil or gas leases are specifically exempt. Municipalities may also levy property taxes on the same basis as the state, but there are limitations on their ability to do so. Eligible properties are valued by several techniques, including market value, replacement cost, actual cost, and economic value. Property used for exploration is valued at fair market value. Property used in production and transportation is valued with consideration to the actual cost incurred and the economic life of proven reserves; valuation is generally on the basis of replacement cost less depreciation based on the economic life of proven reserves. This tax is not included in the empirical work in Chapter 6.

Alaska has a corporate income tax which applies to oil and gas exploitation. It has been subject to many changes over the years and only the recent situation is described here. In the mid-1970s taxable income for the purposes of Alaskan income tax was broadly comparable with that defined for federal income-tax purposes, with a few minor exceptions. There was then a normal tax rate of 5.4 per cent and a surtax rate of 4 per cent, with a surtax exemption of $50,000 of taxable income. Where a corporation received income from activities inside and outside Alaska, it had to apportion its entire taxable income as determined in the Multistate Tax Compact, whereby business income is apportioned to a state by a uniform formula consisting of three factors – property, payroll, and sales. The property, payroll, and sales in Alaska become the numerators of three fractions, while property, payroll, and sales everywhere become the denominators. The three fractions are then averaged, and business income is apportioned to the state by multiplying the total taxable income by that average. The apportionment formula works as follows:

$$\text{All net income} \times \tfrac{1}{3}\left(\frac{\text{Alaska property}}{\text{Total property}} + \frac{\text{Alaska Payroll}}{\text{Total Payroll}} + \frac{\text{Alaska Sales}}{\text{Total Sales}}\right)$$

$$= \text{Alaska Net Income}$$

Property owned by a taxpayer is valued at historic cost.

After the tax base is determined and the apportionment formula is calculated, it is necessary to determine which portion of the tax base is subject to apportionment. The amount of income subject to apportionment is the net income from the unitary business, and the accounting method used to determine this net income is the combined report. The idea is to combine the net income from the entire unitary business. The business income of the entire enterprise is then apportioned to Alaska using the three-factor formula.

The Alaskan government became unhappy about the determination of the effective tax base around 1977. For example, there was concern about the erosion of the tax base because of U.S. tax incentives. (This followed because in essence the base for Alaska income tax followed that of the federal system.) Another area of dissatisfaction concerned Alaska's share of the income earned by a company operating in more than one state. There was dissatisfaction with the three-factor formula described above, especially as it applied to oil companies. It was argued that the use of the sales factor produced a great distortion of oil company activity in Alaska, because the total value of sales of petroleum products is assigned only to the state of final destination where the sale is made; no value is assigned to the state where the oil is produced. The effective rate of tax on income from the Prudhoe Bay field was estimated at the time at 2 to 3 per cent.

In 1978 the state passed the Oil and Gas Corporate Income Tax Act. This included a new section (AS 43.21) which provided that, as far as oil production is concerned, the income tax would be based on gross income minus (1) royalties, (2) oil and gas severance and property taxes, (3) direct operating costs, (4) depreciation on property used directly for producing and preparing oil or gas for pipeline transport, (5) amortization of lease-acquisition costs, (6) uncapitalized interest not exceeding that portion of total interest paid by the consolidated business of which the corporation is a part, (7) unsuccessful exploration expenses incurred after 1971, and (8) directly attributable overhead expenses. The portion of the total interest allowed is determined by multiplying the total interest (reduced by inter-company transactions within a consolidated business) by a fraction, the numerator of which is the value of the corporation's real and tangible personal property used in the production of oil or gas from a lease, and the denominator of which is the value of all real and tangible property owned by the consolidated business. A consolidated business was defined as one where control of an associate or subsidiary was at least 50 per cent. Under the new act, net losses of a taxpayer could be carried back not more than three years and carried forward not more than seven years.

As far as the various deductions are concerned, royalties, production taxes, and *ad valorem* taxes are treated as expenses, as are direct operating costs. The deduction for lease-acquisition costs cannot be utilized until the start of commercial production from the field to which the lease relates or until the lease is abandoned. Lease-acquisition costs are amortized, the amount of amortization allowed in any year being given by the formula

$$\text{Unamortized acquisition cost} \times \frac{\text{Number of barrels produced in year}}{\text{Number of barrels of remaining proved reserves}}$$

While exploration costs are expensed, allowances for development costs may not be utilized until commercial production from the field to which they relate commences or until the lease is abandoned. Development costs are depreciated and the amount of depreciation in any year is given by the following formula:

$$\text{AC x}\ \frac{\text{Number of barrels produced that year (Btu equivalent)}}{\text{Number of barrels of remaining proved reserves (Btu equivalent)}}$$

where AC = Average undepreciated costs for the year

Development costs include payments for wells, facilities, and equipment for the lease in question. It is understood that depreciation of all development costs by the sum of the years digits method over an 11-year period is permitted.

In 1981 further changes were made to the income tax following disputes with oil companies. Section AS 43.21 was repealed. The taxpayer's apportionable income is based on the federal taxable income of the taxpayer's consolidated business. Modifications were made to taxes deductible for federal income tax and to the Alaskan system of depreciation and depletion discussed above. Corporations engaged in oil and gas production or pipeline transportation now have their business income apportioned to Alaska under the Multistate Tax Compact but with some modifications. The sales factor specifically includes tariffs for pipelines. An extraction factor has been introduced and is now substituted for the payroll factor. The extraction factor has as its numerator the number of barrels of oil produced by the taxpayer in Alaska (net of royalty) plus one sixth of his gas production in Alaska; the denominator is the sum of the taxpayer's consolidated oil production (net of royalty) and one sixth of his total gas production (net of royalty).

The basic corporate tax rate is now 9.4 per cent, with lower rates ranging as low as 1 per cent for small amounts of taxable income. There are no formal ring-fence provisions in Alaska.

Texas

In Texas mineral rights are generally vested in the owner of the land. He may enter into a leasing agreement for the exploration and development of his petroleum interests. In such cases the exploitation of petroleum is still subject to the laws of Texas and to any relevant federal laws. The private landlords are able to charge royalties just as governments do, and for many years a rate of 12½ per cent of wellhead value was common. In the 1970s rates rose with the escalation of oil prices and rates exceeding 20 per cent became common. In more recent years rates have fallen again. A figure of 16⅔ per cent has been employed in the empirical work in this study.

In Texas there is a production tax. Since 1957 this has been levied at the rate of 4.6 per cent of the market value of the oil produced or 4.6 cents per barrel, whichever yields the greater amount. The tax is levied on the net production of the investor. There is also a very small additional tax on oil production known as the Regulatory Tax or Tax Levy. Since 1935 this has been at the rate of 3/16 of one cent per barrel produced, levied on the same basis as the production tax.

As elsewhere, local governments levy property taxes. Unique among petroleum-producing states in the United States, Texas local governments include the present value of petroleum reserves in the ground in the base of the property tax. In fact, the base of the tax is essentially the net present value of the reserves in question. Royalties, production tax, all expected exploitation costs, and any further taxes are allowed as deductions. In practice the investor and the authorities discuss and agree future revenues and costs prior to tax assessments being made. Discount rates of 14 to 15 per cent are employed in determining net present values. The rate of property tax varies considerably from one county to another. The effective average rate for the state is at least 2 per cent, though in some cases it is much lower; for example, in Maverick it is 1.025 per cent. A figure of 2 per cent has been employed in the empirical work in this study.

There is no state income tax in Texas. A franchise tax, related to the capital employed by the enterprise, is payable by every business in Texas. It was not thought appropriate to include the franchise tax in the present study.

In Texas, oil producers are subject to the federal taxes discussed above, namely, the federal income tax and the Windfall Profits Tax.

(10) Canada

In this study the operation of the regimes existing prior to the National Energy Program (NEP), during the NEP, and after the abolition of the NEP are separately examined. These three schemes have not been static and their development is described below.

Pre-NEP System

(a) Alberta

In Alberta the provincial government holds petroleum rights for around 85 per cent of the total land. Prior to 1976 crown petroleum and natural gas rights were disposed of by a variety of vehicles including reservations, permits, licences, and leases. Since 1976 all crown rights have been disposed of as Petroleum and Natural Gas Licences or Leases. Requests to the Minister of Energy for licences for exploration are either refused or advertized for sale by public tender. The licensee may subsequently apply for a lease for petroleum and natural gas rights to undertake production in lands inside his licence area. Production leases are obtainable either by bonus bid or by converting an exploration licence. Such leases have an initial term of five years, after which continued leases can be obtained.

The Alberta government obtains revenues from bonus bids, lease rentals, royalties, and income tax. Royalties constitute the largest single source. Following the 1973/1974 OPEC oil price increases, the royalty system was changed from a simple percentage system, such as is employed in most countries, to a more complicated scheme, introduced in 1974, which distinguished between "old" oil and "new" oil. "Old" oil refers to crude oil produced from a well discovered before April 1, 1974, and "new" oil to that produced from a well discovered on or after that date or to an enhanced-recovery scheme effective on or after January 1974.

The basic royalty formula is expressed in relation to a well and applies on a monthly basis. The formula is:

$$R = S[\,1 + k\,(\frac{A - B}{A})\,]$$

where R = monthly royalty in barrels per well

S = a base royalty determined by a schedule described below

k = "royalty factor"

A = par price for the month

B = "select price" for the month

The value of S depends upon the level of production from the well. For production levels up to 1,200 barrels per month, $S = (\text{Production})^2/8000$. For production exceeding this figure $S = 180 + 0.25\,(\text{Production} - 1200)$. The royalty factor, price, and par select price are given by the government each month. Over the past decade, the k factor has only occasionally been changed, though more frequent changes will take place in future years. In the immediate pre-NEP period, the value of k was 1.5178 for "old" oil and 0.603 for "new" oil. Since the par price (A) is a function of deemed average field values, it has changed frequently. The value of B was CAN$4.71 per barrel; the select price has not been changed very often. The operation of the formula is such that royalties payable are a function of well-production volumes, oil prices, and the time of discovery.

The Alberta government has for many years employed various fiscal devices to encourage exploration and development. In December 1974 several such devices were introduced, two of which related directly to royalties. These were the geophysical and the exploratory drilling incentive schemes. The geophysical incentive scheme gave a credit for an agreed geophysical program. The credit was allowed against royalties, rentals, and cash bonuses. The size of the credit, whose value has been changed by the government on several occasions, was related to the geographic location of the activity and the extent of the area covered.

Under the exploratory drilling incentive, credits can be obtained against royalties, rentals, and bonus payments. Generally the credits are related to the depth of the well drilled and its location. To qualify for the incentive, exploratory wells had to be located more than three miles from a well cased for production or, if less than three miles, drilled significantly deeper than cased wells. The terms of the incentive scheme have varied considerably over the years. Under the 1974 rules, royalty- and tax-free periods of five years from the start of production were also given. Under the rules introduced in January 1978, in the Central Area, the first 2000 feet below the surface had a zero credit; the credit then rose incrementally to reach a maximum of CAN$550 per foot when a drilling depth of 17,000 feet was attained; at 17,000 feet the cumulative credits became CAN$1.85 million. In the Northern and Foothills areas, the incentives were more generous.

The pre-NEP fiscal system includes income taxes levied by the federal and Alberta governments. Both the federal and Alberta systems of income tax underwent major changes following the large oil price increases of 1973/1974. The system in force immediately prior to the introduction of the NEP is described here. In 1980 the federal rate of corporate tax is 46 per cent with an abatement of 10 per cent to reflect the provincial income taxes payable. The federal system incorporates a large number of allowances and deductions. Broadly speaking, oil and gas exploitation activities are subject to income tax only after the recovery of all current costs, exploration costs, and a large portion of development and capital costs. There is also an investment tax credit available on eligible capital investments; the rate is 7 per cent unless the property is located in areas of Canada designated under the Regional Development Incentive Act, in which case it is 10 per cent. The amount of the tax credit is deducted from the federal income tax otherwise payable. This amount must also be deducted from the capital cost of the property before calculation of the capital cost allowance. Depreciable tangible assets employed in oil and gas production and exploration activities obtain capital cost allowances, generally at the rate of 30 per cent per annum on a declining-balance basis. Well-operating costs and general and administrative costs are normally expensed. A resource allowance was introduced in January 1976 to compensate for the disallowance of provincial royalties as a deduction for federal income tax. This allowance equals 25 per cent of production profits, calculated after operating costs and capital cost allowances but before other deductions.

In Canada intangible assets are divided into two categories, namely Canadian Exploration Expenses (CEE) and Canadian Development Expenses (CDE). All CEE costs can be written off on a 100 per cent first-year basis. Intangible development costs and resource-property acquisition costs are included in CDE, and these are written off on a 30 per cent declining-balance basis.

In the pre-NEP period a depletion allowance was available. The normal deduction was the lesser of (a) 25 per cent of production income after deducting operating and overhead expenses, capital cost allowances, resource allowance, Canadian exploration and development expenses, and interest, or (b) one-third of the earned depletion base, consisting of Canadian exploration and development expenses but excluding Canadian resource-property acquisition costs. Depletion earned in any year but not actually utilized because of the 25 per cent maximum could be carried forward. More generous depletion provisions were available for non-conventional oil and tertiary recovery systems.

In Canada losses can be set against all other income of the taxpayer in the year in question. If they are then not fully covered, they may be carried back for one year. If full relief has still not been attained, a carry-forward of losses for five years is allowed.

The Alberta government levies income tax at the rate of 11 per cent. Taxable income is generally determined as for federal tax, but the Alberta scheme differs with respect to the treatment of royalties. Whereas provincial royalties are disallowed as a deduction for federal income-tax purposes, two reliefs are available in Alberta, namely, the royalty tax rebate and the royalty tax credit. Basically, the royalty tax rebate eliminates the Alberta income tax on crown levies on the production of petroleum in excess of the resource allowance. Its value is 11 per cent of the amount of all provincial levies in excess of the resource allowance, where relevant provincial levies include disallowed royalties and lease rentals and bonuses. The rebate can only reduce Alberta tax; it cannot make it negative. Unused rebates can be carried forward indefinitely.

The royalty tax credit is designed to compensate the investor for the federal disallowance of provincial royalties. In the pre-NEP period the credit equalled 25 per cent of royalty income paid to the Government of Alberta. A maximum credit of CAN$1 million per year was in force to curtail benefits to large producers. The credit has to be used firstly to reduce Alberta tax payable, after deduction of the royalty tax rebate; a credit in excess of Alberta income tax otherwise payable leads to a cash rebate.

(b) Canada Lands

Canada Lands refers to the Territories and to offshore areas. Up to 1976 most acreage in the Canada Lands was disposed of through Exploratory Permits. These were issued for periods of between three and six years, depending on the latitude of the area, with renewals obtainable for up to six years. Permittees had the exclusive option to obtain Oil and Gas Leases for a part of the Canada Lands included in their permits, but no more than 50 per cent of a permit area could be converted to a lease. In addition to initial fees, annual rentals are payable. In 1976 a new transitional phase between exploration and production, called the Provisional Oil and Gas Lease, was introduced. This allowed the lessee to explore and delineate but not to produce. Production licences were issued for 10-year periods, with renewals permitted. Provisional leases and production licences could include the total permit area. In 1977 new regulations were issued: exploration agreements were for 10 years with renewals, and operators were given the right to explore and produce.

On Canada Lands, a system of basic royalty plus Progressive Incremental Royalty (PIR) was proposed in 1976, though the legislation did not come into effect until 1982. The basic royalty was 10 per cent. The PIR was to be a tax rather than a royalty. It would be calculated on a field basis according to a specified definition of profitability. The tax was applied to annual profits remaining after exploitation costs, fixed royalty, and federal income tax had been recovered and after a basic profit on the investment had been returned. The basic profit allowed on the investment was intended to be sufficiently large to absorb the cost of exploration, since it was thought that it would not be possible to assign exploration costs to an individual discovery.

Profits for PIR purposes were computed by establishing a ring fence around each field. All calculations were then done on the basis of costs and revenues from within the ring fence. The profit for the PIR calculation was determined as follows:

$$P = REV - EXP - ROY - FAB - CAL$$

where REV = revenues at the field gate

EXP = operating expenditures

ROY = the basic federal royalty of 10 per cent

FAB = the federal abatement equal to the theoretical income tax payable if calculated on a ring-fenced basis

CAL = capital allowances calculated on a one-sixth straight-line basis

The PIR was then calculated according to the following formula:

$$PIR = (P - 0.25 \times I) \times 0.4$$

where I = the remaining outstanding ring-fenced investment with depreciation at 10 per cent per annum of the declining balance

The capital allowance provided for the write-off of investment at the maximum rate of one sixth per year starting in the year of the investment. Allowances not utilized in any year could be carried forward and used in later years. Capital cost allowances and earned depletion had to be taken in the same manner as for federal income-tax purposes. Exploration expenditures outside a field were not deductible in calculating the federal abatement nor in any other way for calculating PIR. The operation of the formula meant that PIR did not apply in any year unless profits divided by depreciated field investment exceeded 25 per cent. Under the formula, as profitability increased the effective rate of tax would also increase, but at a slower pace.

In 1975 the national oil company, Petro-Canada, was created. In its early years, it acquired a number of stakes in other oil companies, including 100 per cent of Atlantic Richfield's interests. From August 1977 when companies applied for renewal permits on the Canada Lands, Petro-Canada was given back-in or participation rights in such permits. The state company was also given prior rights to selecting crown reserve lands. When a renewal permit was being applied for on lands where no significant discovery had been made, Petro-Canada was enabled to have a 10 per cent interest in cases where the Canadian interest was between 25 per cent and 35 per cent; in cases where the Canadian interest was under 25 per cent, Petro-Canada could acquire additional interests, not exceeding 15 per cent, of 1 per cent for every 1 per cent that the Canadian participation fell below 25 per cent.

Under the pre-NEP system, crude-oil price controls played a significant role in Canada. In essence these transferred some of the economic rents from exploiting the natural resource to crude-oil consumers. Controls on wellhead prices were introduced in 1973. In support of the scheme an Export Tax on oil sold to the United States was also introduced; this tax approximated to the difference between the controlled Canadian price and the U.S. price. Under the Oil Import Compensation Program, introduced in 1974, a single crude-oil price across Canada was established subject only to transportation and quality differences. Revenues from the Export Tax were used to subsidize consumers in the eastern part of the country, which imported oil at world prices.

From 1974 onwards, frequent meetings took place between the Alberta and federal governments on the question of wellhead prices, with the Alberta government continually pressing for increases. In the late 1970s Canadian prices were significantly below world levels; for example, in the first few months of 1979, the price was CAN$13.04 per barrel. In the late 1970s Canadian prices had been increasing at the rate of CAN$1 every six months. The declared aim of the federal government in the pre-NEP period was to move domestic prices towards international levels.[6] In this study, where the pre-NEP system has been simulated, it has been assumed that Canadian and world prices eventually converge on a landed basis.

NEP System

The National Energy Program (NEP) was introduced in October 1980 and heralded major changes in Canadian petroleum policies. The NEP system covered leasing, taxation, pricing, and participation by Petro-Canada. The NEP system was not a static one, however, and amendments were made in every year of its existence. In the original version introduced, four new taxes, namely, the Petroleum and Gas Revenue Tax (PGRT), the Natural Gas and Gas Liquids Tax (NGGLT), the Canadian Ownership Special Charge (COSC), and the Petroleum Compensation Charge (PCC).

From the viewpoint of petroleum producers the most important innovation was the PGRT, originally levied at a rate of 8 per cent. It was essentially a tax on production revenues net of operating costs and Canadian Exploration and Development Overhead Expenses (CEDOE). Apart from these items, deductions were not available for capital costs. Taxable revenues were reduced by the resource allowance, but Alberta crown royalties were not deductible. A concession was given for investment in enhanced-recovery schemes: the PGRT from such projects did not become payable until eligible capital expenditures had been recovered from production revenues. The PGRT paid was not deductible for purposes of either federal or Alberta income tax. A small-producer credit was available for working interests held by corporations.

The NGGLT was imposed on all gas sales. The rates were set to rise from CAN$0.30 per thousand cubic feet (mcf) in November 1980 to CAN$0.75 per mcf in January 1983. The purpose of the COSC was to finance increased public ownership of the public sector. It was levied on crude oil as it entered the refinery, on natural gas at the processing plant stage, and on all imported oil and natural gas. The rates were set in May 1981 at CAN$1.15 per barrel and CAN$0.15 per mcf.

The PCC in effect subsidized the price of imported oil. This subsidy had previously been borne by the federal government but was now passed on to consumers via the "blended" oil price system, which made the cost of crude oil to refiners a weighted average of costs from all sources of supply. The PCC paid importing refiners in Canada an amount sufficient to reduce the average cost of imported oil to the average cost of Canadian oil. In addition, the scheme could be employed to raise net revenues for the government. The NGGLT was similar, to the extent that it placed a wedge between the producer and city-gate price, but the NGGLT was part of general tax revenues.

Along with the new taxes the government introduced a number of fiscal incentives in 1980. The depletion allowance was to be phased out over a period extending to 1984 and it was replaced by the Petroleum Incentives Program (PIP), which took effect immediately. This program was financed and administered by the federal government except in Alberta, where the provincial government undertook this function from 1981 onwards. The size of the incentive payments depended on the degree of Canadian ownership, the type of investment, and the location of the activity. For *exploration* in Alberta, for example, when the degree of Canadian ownership in 1981 was at least 50 per cent incentive payments were 10 per cent of approved costs in 1982 and 1983 and 15 per cent thereafter. When the degree of Canadian ownership reached at least 60 per cent (according to 1981 rules; minimum level increased for later years, up to 65 per cent in 1986), the size of the payments increased to 25 per cent of approved costs. When Canadian ownership reached 65 per cent (1981 rules; minimum levels in subsequent years were higher, up to 75 per cent in 1986), the payment was increased to 35 per cent. For *development* expenditures on provincial lands, Canadian ownership of at least 50 per cent in 1981 brought payments of 10 per cent of approved costs from 1982 onwards. When Canadian ownership reached the top level of 65 per cent (1981 rules; 75 per cent by 1986), payments became 20 per cent of eligible expenses. For exploitation of non-conventional oil, including oil sands and enhanced oil-recovery projects, incentives equalled those for development expenditures.

The PIP scheme was linked to the tax changes introduced at the same time and similar definitions were employed. Expenditures deducted against income taxes had to be reduced by incentive payments received. In the empirical work undertaken in Chapter 6, the tax takes in Canada have generally been shown net of PIP payments made.

In the original version of the NEP, oil price controls involved the division of oil into three categories, namely, (1) from oil sands, (2) tertiary recovery oil, and (3) conventional oil. Wellhead prices under each category were controlled. The price of conventional oil was set to rise from CAN$17.75 in January 1981 to CAN$66.75 in 1990; the rate of escalation was set at CAN$1 every six months to the end of 1983, then CAN$2.25 every six months to the end of 1985, and then CAN$3.50 per six-month period until the price of conventional oil reached a quality-determined level relative to the oil sands "reference price," which was defined as "the *lesser* of CAN$38 per barrel effective January 1 1981 escalated annually thereafter by the Consumer Price Index, *or* the international price."[7]

The NEP introduced several innovations regarding Canada Lands. Petro-Canada was given a 25 per cent interest in every petroleum right on a carried-interest basis. This could be converted to a working interest at any time prior to the authorization of a production system for a field. Petro-Canada's rights were applicable to all existing interests. On Canada Lands a minimum of 50 per cent Canadian ownership (private or public) was also required. The NEP reaffirmed the government's desire to legislate for a royalty tax system incorporating a 10 per cent basic royalty plus the introduction of the PIR; the NEP did not, however, introduce such a system.

On Canada Lands the PIP payments for exploration were set at higher levels than for the provinces. For Canadian ownership less than 50 per cent, payments were 25 per cent of approved costs; for Canadian ownership of at least 50 per cent, payments were set at 35 per cent for 1981, 45 per cent for 1982 and 1983, and 50 per cent thereafter; when Canadian ownership reached 60 per cent or more (1981 rules; higher minimum levels in later years, up to 65 per cent in 1986), payments were set at 65 per cent; when Canadian ownership reached at least 65 per cent (1981; 75 per cent in 1986), payments were set at 80 per cent.

In 1981, following protests by the Alberta government against the NEP, modifications were made to the scheme and formalized in the New Energy Agreement of September 1981. In essence this agreement acknowledged the federal government's right to introduce new taxes on petroleum exploitation in return for substantially increased wellhead prices. In the agreement the distinction between "old" and "new" oil was adopted, with conventional oil discovered before 1981 being defined as "old" oil and "new" oil being oil discovered from 1981 onwards or produced from oil sands, from locations offshore, or by tertiary recovery techniques. The "old" oil price was set to rise from CAN$23.50 in January 1982 to CAN$57.75 in July 1986 but with a cap of 75 per cent of the world price. A "new" oil reference price (NORP) was set to rise from CAN$45.92 in January 1982 to CAN$77.48 in July 1986 with a cap of the world price.

Several other tax changes were introduced in 1981. The PCC was confined to financing oil-import compensation and oil qualifying for NORP. At the end of 1986 the PCC fund was to become zero. The

NGGLT was set at zero on gas exports; on domestic sales the rate was set such that the Toronto city-gate price was 65 per cent of the btu equivalent of oil at the Toronto refinery gate. The PGRT was set at a rate of 16 per cent from January 1, 1982; with the resource allowance of 25 per cent of production revenues being allowed as a deduction, the effective rate became 12 per cent. An Incremental Oil Revenue Tax (IORT) was introduced at the rate of 50 per cent of the incremental "old" oil revenues after the deduction of royalties. Incremental "old" oil revenues were the difference between actual revenues and revenues that would have been received had the October 1980 (NEP) prices prevailed. Incremental revenues subject to the IORT were not subject to income tax. The IORT was suspended for most producers from June 1, 1982.

As part of the September 1981 agreement, the Alberta government agreed not to adjust its royalty system to obtain more revenue than would be yielded by continuation of the current system.

Regarding incentives, it was agreed in September 1981 that the depletion allowance for Canada Lands should be phased out by 1985. The Alberta government took over the administration and funding of the PIP scheme in Alberta. The federal government retained the right, subject to the agreement of the Alberta government, to change the schedule of PIP rates, the rules for Canadian ownership, and the definition of costs and revenues.

In July 1982 further changes were made to the NEP system and promulgated in the *National Energy Program: Update 1982*. On pricing for existing tertiary recovery projects, the NORP applied if the projects in question paid royalties no higher than those for "new" oil. Similarly, the NORP applied to production from wells where production had been suspended for three years and now qualified for "new" oil royalties. The PGRT was reduced from 16 per cent to 14.67 per cent for the period June 1, 1982, to May 31, 1983; after the resource allowance, the effective rate became 11 per cent. An annual credit of up to CAN$250,000 was given against the PGRT. This was termed the small-producer's exemption. The PGRT rate on synthetic oil production was reduced from 12 per cent to 8 per cent for the period January 1, 1983, to December 31, 1984. Other changes included the setting of the IORT to zero for the period June 1, 1982, to May 31, 1983. The depletion allowance was granted for tertiary recovery projects, subject to agreement with provinces on royalty relief.

In April 1982 the Alberta government markedly increased the value of the select price in its royalty formula to $6.50 per barrel. The intention was to offset higher operating costs. The k factors in the royalty formula were set at 1.076837 for "old" oil and 0.615256 for "new" oil. Increases were made to the small producers' royalty tax credit: for the period September 1981 to December 1983, 75 per cent of crown royalties were allowed as credits, subject to a maximum credit of CAN$4 million per company. At the same time it was announced that, from January 1984, 50 per cent of crown royalties would be allowed as tax credits with a maximum credit of CAN$2 million per company. Several changes were also made to the royalties applied to natural gas exploitation.

By 1982 the regulations concerning credits for the exploratory drilling incentive schemes reflected some modifications made in 1981. The structure of the incentives remained the same – an incentive exploratory well has to be located more than 4.8 km (3 miles) from a well that has, or warrants, casing for production or, if less than 4.8 km from a cased well, is drilled significantly deeper than the cased one. Footage is divided into classes A and B. Under the Class A footage scheme, credits increase with drilling depth – from CAN$73 per metre for depths between 600 and 900 metres to a maximum of CAN$1,250 per metre at depths of 1,200 metres; at that depth the cumulative credit is CAN$2.67 million. Under the Class B footage scheme, credits in the Central Area increase from CAN$55 per metre for depths between 600 and 900 metres to CAN$938 per metre at depths of 6,000 metres, where the cumulative credit is CAN$1.99 million. For qualifying footage, a five-year royalty holiday is available.

In 1982 the Oil and Gas Act was passed, enacting proposals for Petro-Canada participation and the PIR discussed above. Petro-Canada was given the right to a 25 per cent reservation share, which could be converted into a working interest at the beginning of the development phase of the project. The private sector was to be compensated for carrying Petro-Canada's share of pre-1982 exploration costs by *ex gratia* payments equal to 25 per cent of these costs grossed up by 15 per cent per year to allow for interest and inflation to the end of 1980. These payments were to be made out of Petro-Canada's share of production. Post-1980 exploration costs were to be compensated by the PIP grants. After participation or back-in by Petro-Canada, the crown company pays its share of all subsequent costs.

The 1982 act phased out the existing system of licences and permits and replaced them with Exploration Agreements and Production Licences. Exploration Agreements incorporate cash bonuses, work programs satisfactory to the Department of Energy, and equity participation. They have a normal life not exceeding five years, but extensions can be negotiated. Production Licences generally require a minimum Canadian ownership of 50 per cent. Where applicants have less than 50 per cent Canadian ownership, the Crown procures a share equal to the difference between 50 per cent and the actual proportion of Canadian ownership of the applicant; this crown share is then auctioned off to parties with 75 per cent Canadian ownership.

Post-NEP System

In 1985 both federal and provincial governments made major changes to the fiscal packages applied to petroleum exploitation. The Western Accord in March 1985 instigated the changes. Oil prices of all categories were deregulated from June 1, 1985, signifying the intention to move towards a more market-sensitive system of pricing for natural gas. The federal government announced the phasing out of the PGRT – for conventional oil the effective rates (i.e., after the resource allowance) for existing producers were reduced to 10 per cent for 1986, 8 per cent for 1987, 6 per cent for 1988, and zero thereafter; for synthetic oil the rates for the same years are 6 per cent, 4 per cent, 2 per cent and zero. For new production commencing after April 1, 1985, the PGRT is removed. Companies currently not paying income tax can obtain up to 30 per cent of new exploration expenditure as a write-off against their PGRT bill.

Several federal government taxes – namely, the IORT, the PCC, COC, and the NGGLT – were all abolished. The PIP system was generally abolished after the end of March 1986, although it has been retained for exploration expenses incurred in existing commitments in the Canada Lands for a grandfathering period extending no later than December 31, 1987.

In the budget of 1986, major reforms were made to the structure of the corporate income tax. The federal tax rates are being reduced over the period 1986 to 1990. The rates will vary according to the type of activity. For large companies engaged in petroleum exploitation, the rate falls from 36 per cent in 1986 (after the 10 per cent provincial abatement) to 35 per cent as of July 1, 1987; to 34 per cent from July 1, 1988; to 33 per cent as of July 1, 1989. A 5 per cent surcharge was introduced in 1986, falling to 3 per cent from 1987 onwards. If the 5 per cent surcharge continues the rate would be 33.99 per cent as of July 1, 1989. Where no provincial tax applies, as in offshore territories, the rate would be 43 per cent from July 1, 1989, or 44.29 per cent including the 5 per cent surcharge.

With the reduction in tax rates come changes to the investment tax credit. The general rate is reduced to 5 per cent in 1987, 3 per cent in 1988, and zero thereafter. In the offshore Atlantic areas the rate continues at 20 per cent.

In July 1985, the government of Alberta revised its royalty system, retaining the basic formula but changing some of the values. As of August 1985 the select price was CAN$40.90 per cubic metre, the par price CAN$231.25 per cubic metre, and the k factor 0.546154 for "new" oil and 1.007692 for "old" oil. Policy has been to collect for a reference well 21.67 per cent of the first CAN$40.90 per cubic metre and a marginal rate of the portion of the par price in excess of CAN$40.90 per cubic metre.

To provide further incentives, the Alberta government increased the royalty tax credit. From April 1, 1986, this was increased to 75 per cent of royalty liabilities with a maximum of CAN$3 million per company. The timing coincided with the termination of the PIP scheme in Alberta. A new exploration incentive program was also introduced, to take effect from June 1, 1985, to May 31, 1988. The incentive takes the form of either a 12-month royalty-free period for each eligible well, to a maximum of CAN$1 million, or a royalty exemption based on volume and calculated on a depth-related schedule, as shown in Table 3.12.

Table 3.12
Oil Royalty Incentive, Alberta, 1985

Producing Depth[b] (metres)	Cumulative Barrels of Exempted Royalty Oil per Eligible Well[a]		
	Northern-Foothills	Central	Plains
500	1,750	900	700
1,000	3,600	1,800	1,500
1,500	5,800	3,300	2,600
2,000	8,500	4,800	3,900
2,500	11,200	7,600	5,400
3,000	15,500	10,700	7,000
3,500	20,400	15,600	8,750
4,000	25,700	19,900	10,500

Notes: a. Cumulative barrels is the amount of royalty oil exempted from payment under the Petroleum Royalty Regulations.
b. Producing depth refers to the base of the deepest producing zone.

The CAN$1 million maximum royalty exemption applies to all wells. The definition of royalty free has been expanded to apply to all conventional wells drilled outside existing pool boundaries, but does not include off-target wells drilled on or adjacent to existing pool boundaries. There is a similar incentive for gas exploration, with the maximum royalty exemption increased to CAN$2 million per well.

At the end of October 1985 the federal government announced a new frontier energy policy to complement the Western Accord. A new act, the Canada Petroleum Resources Act, will replace the Canada Oil and Gas Act. Under this legislation Exploration Licences, Significant Discovery Licences, and Production Licences will be issued, generally on the basis of competitive bidding. The government is reducing its interventionist powers relating to drilling obligations and depletion rates; Petro-Canada will have no participation rights under the proposed act and the company will operate on essentially the same basis as any other private company. The proposed legislation does require a 50 per cent level of Canadian ownership at the production stage.

Regarding fiscal terms, the new frontier policy abolishes the existing basic royalty of 10 per cent and the PIR. In their place will be a royalty which, prior to "payout" of the project, starts at 1 per cent and rises to 5 per cent in increments of 1 per cent every 18 months. After project payout has been achieved, the royalty rises to 30 per cent of net cash flow. Payout occurs when gross revenues minus royalties, exploration costs (where relevant), and operating costs exceed investment and when a stipulated rate of return on the outstanding capital has been obtained. A rate of return of 10 per cent has been employed in the analysis here. Corporate taxes are not included in the definition of payout.

The new policy also includes a 25 per cent investment royalty credit, which is applied to well costs for frontier exploration equal to or below CAN$5 million. This credit is applied against royalties otherwise payable. To further encourage exploration in frontier areas, the federal government announced the introduction of a 25 per cent Exploration Tax Credit (ETC). This is applicable throughout Canada, including Alberta, to exploration expenses above CAN$5 million per well. The provision, which started on December 1, 1985, and terminates on December 31, 1990, applies only to Canadian Exploration Expenses (CEE) which are not eligible for PIP payments. The credit earned is used to reduce federal income tax otherwise payable. An extra feature of the ETC permits companies that are unable to utilize the credit to apply for a refund of up to 40 per cent of the credit not utilized. Any ETC claimed or refunded reduces cumulative CEE in a manner similar to the operation of the ITC in reducing the capital cost of an asset for purposes of capital cost allowance.

Following the major falls in oil price in 1986, the Alberta government introduced further changes. On April 1, 1986, new incentives were provided. The level of the provincial royalty tax credit was increased from 75 per cent to 95 per cent, with a maximum of CAN$3 million annually per company, for the period to December 31, 1986. A second incentive was a temporary Exploratory Drilling Assistance Program, under which companies could reduce royalties by obtaining a credit of 50 per cent of the cost of drilling exploratory wells in 1986 against net royalties payable on or after April 1, 1987.

At the end of April 1986 the federal government also announced a package of measures to help the petroleum industry. The reliefs were concentrated on the small and medium-sized companies and included the suspension of the PGRT until the end of 1986. A particular objective was to facilitate the maintenance of production from oil sands. In September 1986 the PGRT was completely abolished with effect from October 1.

In October 1986 the Alberta government introduced further incentives. There were four components: (1) The royalty tax credits were extended to the end of 1987. (2) A new drilling incentive program based on royalty holidays was established. Wells spudded in the period October 1, 1986, to October 31, 1987, are exempt from royalties for five years; those spudded in the period November 1, 1987, to October 31, 1988, are exempt from royalties for three years; those spudded in the period November 1, 1988, to October 31, 1989, are exempt for one year. (3) The royalty burden was reduced, principally through changes to the k factor. The basic royalty formula remains unchanged so that the position towards the end of 1986 was as follows:

$$R = S \{ 1 + k \frac{(A - B)}{A} \}$$

where R = monthly royalty in barrels per well

S = base royalty determined as follows:
for PROD (production per well per month) up to 1,200 barrels, $S = (\text{PROD})^2/8000$
for PROD greater than 1,200 barrels, $S = 180 + 0.25\ (\text{PROD} - 1200)$

k = royalty factor: 0.846154 for old oil (discovered before November 1986) and 0.246154 for new oil (discovered after November 1986)

A = par price: CAN$19.85 per barrel for both old and new oil

B = select price: CAN$6.50 per barrel

(4) The final incentive was the establishment of a Small Producer's Assistance Commission, which will operate at arm's length from the government to help small producers.

The federal government proposed another new incentive program in March 1987. The Canadian Exploration and Development Incentive Program (CEDIP) will provide a cash incentive equal to 33⅓ per cent of eligible exploration and development expenditures up to CAN$10 million in any 12-month period. This facility has not been incorporated in the empirical analysis in this study.

There have clearly been a large number of changes in the fiscal system applied to petroleum exploitation in Canada over the last decade. In the empirical work in this study, the effects of the legislation on new exploration and development activities are examined. The fiscal systems employed in the analysis are (1) the regime in force immediately prior to the NEP, (2) the most recent version of the NEP, and (3) the post-NEP system as it existed by the end of 1986.

The 1986 changes to the corporate income tax were structural in character and were not designed with petroleum exploitation in mind. In the empirical work, in comparing the pre-NEP, NEP, and post-NEP systems, it was thought to be most illuminating to keep the basic income-tax position constant. Accordingly, the analysis has been undertaken as if the new corporate income tax system applied in the pre-NEP and NEP schemes.

Notes

1. For a detailed discussion of royalties in Australia see G. Ryan, "Australia: Petroleum Royalties - Part I," *Oil and Gas Law and Taxation Review* 4, no. 5 (1985/86), pp. 121-37, and G. Ryan, "Australia: Petroleum Royalties - Part II," *Oil and Gas Law and Taxation Review* 4, no. 6 (1985/86), pp. 154-59.

2. For a summary see A. Ahkong, "Reform of Indonesian Income Tax Law: Implications for Foreign Investors," *Oil and Gas Law and Taxation Review* 4, no. 2 (1985/86), pp. 38-40.

3. See "Indonesia: Exploration Incentives Still Lacking," *Petroleum Economist* 53, no. 1 (January 1986), p. 25.

4. See text of speech of Finance Minister Encik Daim Zainuddin at ASCOPE Conference, Malaysia, December 5, 1985. See also *Petroleum Economist* 53, p. 25.

5. For a clear discussion of the system as illustrated in agreements signed in 1984, see M. Davies, "The 1984 Concession Agreements in the Arab Republic of Egypt," *Oil and Gas Law and Taxation Review* 4, issue no. 5 (1985/86), pp. 138-43.

6. Canada, Department of Energy, Mines and Resources, *An Energy Strategy for Canada: Policies for Self Reliance*, Summary, (Ottawa: Dept. of Energy, Mines and Resources, 1976), p. 24.

7. Canada, Department of Energy, Mines and Resources, *The National Energy Program*, (Ottawa: Dept. of Energy, Mines and Resources, 1980), p. 28.

Chapter 4

Effects of Fiscal Devices Applied to Petroleum Exploitation

Criteria for Assessing Performance

The performance of fiscal devices applied to petroleum exploitation may be assessed against several criteria. An obvious one is economic efficiency. In the present context the avoidance of economic distortions means that the fiscal mechanisms should not produce disincentives to develop new fields or explore for new reserves. Economic efficiency further entails that neither premature abandonment of fields nor disincentives to undertake incremental investments should be produced. An efficient fiscal system would not produce any incentive to engage in "overinvestment" or "gold-plating" expenditures. Nor would an efficient fiscal system alter depletion rates. In sum, there is an argument on resource-allocation grounds that incentives to explore, develop new fields, and deplete reservoirs should remain unimpaired compared with the pre-tax situation. The extent to which a fiscal system induces changes to decision making in these areas gives one measure of the inefficiency of the scheme in question.

In making decisions regarding the allocation of resources to any activity, investors will consider the opportunity cost of their funds. It is arguable that if all industries faced the same tax schedule then that common tax would be part of the opportunity cost of the factors of production and so could not be claimed as part of economic rent. The petroleum industry is highly international in character and investors certainly compare prospects in different countries. Additionally, returns in non-petroleum activities may be considered by petroleum companies.

As is clear from Chapter 3, the fiscal arrangements applied to petroleum exploitation vary enormously from one country to another. There is no uniform income tax facing investors. In some countries, such as Egypt, investors in petroleum do not pay income tax at all. In others the income tax contains provisions (such as different rates of tax or depreciation provisions) which have the effect of making effective rates very different from those applied elsewhere. Conventional income taxes applied to non-petroleum activities also vary considerably from one country to another. In these circumstances it is appropriate to examine the impact of the total fiscal package applied to petroleum exploitation, as compared with the pre-tax situation. This has the advantage of highlighting any economic inefficiencies as discussed above. It is obviously useful to discover the extent to which exploration and field developments are being affected by fiscal devices. Proceeding in this manner also permits conclusions to be made about the extent to which company income taxes introduce disincentives.

The efficiency of a fiscal system can also be judged on its ability to collect economic rents. Economic rents from petroleum exploitation vary with oil prices and the quality of the resource being exploited. An efficient fiscal system would be inherently sensitive to changes in rents brought about by variations in oil prices and exploitation costs, enabling rents to be collected without necessitating discretionary changes by governments. A perceived requirement for discretionary fiscal changes (in an upward or downward direction) introduces undesirable extra uncertainties into the investment environment. Reductions in effective taxes would be demanded if the fiscal system pulled post-tax returns below acceptable levels, whereas there would be pressure for increases in taxes when profits from petroleum exploitation were perceived to be "excessively" large. The desired automatic flexibility in the fiscal system should be sensitive (a) to the range of field sizes and cost conditions in a geological province at any one time, and (b) to changes over time in oil prices as well as in field sizes and cost conditions. Clearly, a system that is directly targeted on economic rents is more likely to perform efficiently in this sense than one that collects the rents in an indirect manner.

The precise share of rents that a system should be expected to collect depends upon the type of system being employed. If a scheme could be devised whereby 100 per cent of the rents could be collected without causing any economic disincentives, distortions, or the need for any subsequent discretionary intervention by governments, there is an obvious case for its introduction. However, it is difficult, if not impossible, to devise such a scheme. The only mechanism that could meet these requirements would be a bidding system, which could result in the bids' accurately reflecting the economic rents.

Tax systems generally will not meet the requirements. A normal tax scheme shares the revenues between different parties. If the fiscal mechanism is not directly targeted on economic rents, it is virtually impossible to collect 100 per cent of the rents without introducing distortions. In a producing province with fields of different sizes and costs, a scheme not directly related to economic rents which does extract 100 per cent of the rents from one field will collect greater or lesser amounts from other fields with different resource qualities. This subject is developed further below. A tax system which is directly related to economic rents will also generally be unable to extract 100 per cent of these rents without causing distortions. A normal scheme incorporates a marginal rate of tax of less than 100 per cent. This means that any incremental rents are shared between investors and governments, and therefore 100 per cent of the rents will not be extracted. If a marginal tax rate of 100 per cent (or more) were imposed, a government could collect 100 per cent of incremental rents, but the resulting system would be economically inefficient – it would introduce incentives to incur "gold-plating" investments or to indulge in other wasteful expenditures; incentives for cost-consciousness would be seriously impaired. On these grounds an efficient tax system should generally aim for less than 100 per cent of the rents.

Profitability of exploitation will vary considerably within any major producing province. A question arising from this is what share of the varying rents should be collected. Should the system extract a constant share or should the share collected increase directly with profitability? The relevant arguments here are in some senses comparable to those relating to the issue of proportional versus progressive income tax: the ability to pay of the recipient of the higher income is greater, and this constitutes one argument for imposing a (proportionately) higher charge on the larger income; similarly, it could be argued that the state should collect a higher share of the rents as profitability increases.

Just as the case for progressive income tax is not a straightforward proposition, however, so the case for the extraction of a progressively higher share of rents is not conspicuously obvious. If a scheme can be devised which satisfies this objective in an economically efficient manner, it could be argued that such a system has the potential to procure more revenue at no extra real cost and should thus be introduced. However, progressive schemes are of necessity complex in their construction, and they risk the distinct possibility of economic distortions being introduced, particularly in the form of the "gold-plating" type of investments. This subject is discussed further in the section on the "Brown Tax" below. If a scheme can be devised which does not introduce such incentives, the case becomes reasonably strong.

It is clear that a scheme which is regressive in its link to the size of the economic rents not only is objectionable on equity grounds but is very likely to introduce disincentives to explore and develop new fields. If the share of rents extracted from investors increases as the rents fall, it is almost certain that any such scheme will result in the take exceeding the rents when profitability becomes low.

In countries where the economic rents are shared by more than one tier of government, additional problems emerge. If fiscal stability is to be maintained, it is important that, once the shares accruing to the respective tiers of government have been agreed, these shares are largely maintained over time, even when the operating environment changes. If major changes in oil prices lead to a large redistribution in the shares of the rents (due, say, to the interaction of the different fiscal instruments with a large price change), the result is likely to be political instability in this area; the tier of government that has done relatively badly will wish to modify the fiscal package. Thus, when the rents are shared between tiers of government an additional requirement for stability is automatic sensitivity to changes in the operating environment with respect to the shares accruing to the different tiers.

In sum, fiscal devices applied to petroleum exploitation can be judged on several criteria. Their ability to avoid the introduction of economic inefficiencies is clearly important. The degree to which a scheme is inherently sensitive to changes in the operating environment is important, because this will determine the extent to which it can extract a given share of rents within a changing environment. This determines the degree of stability in a system over time. There is scope for debate about whether a system should be proportionately or progressively related to the size of the economic rents. Both types of systems can remain economically efficient and be automatically sensitive to changes in the operating environment; a progressive system runs more risk of producing economic distortions, however, particularly through incentives to engage in "gold-plating" expenditures. A tax system cannot efficiently extract 100 per cent of the rents but, if the scheme is well targeted, a high proportion can be collected without distortions emerging. The precise share then becomes a matter of redistribution policy within a society.

Dual Role of Government

As was seen in Chapter 3, governments in most countries are both owners of mineral rights and general tax-levying authorities. In their capacity as landowners they attempt to collect economic rents. In their capacity as tax-levying authorities they levy taxes on petroleum exploitation and other corporate activities in the knowledge that the measures are not specifically directed at economic rents. Sometimes (as in Egypt) the distinction is not recognized by the existence of separate levies and all payments are incorporated in one imposition.

It is often not readily apparent to what extent fiscal measures not directly intended to collect economic rents do in practice either contribute to the achievement of this objective or produce economic distortions. Such effects are discussed in Chapter 7. The present chapter discusses the general effects of individual fiscal measures and quasi-fiscal measures related both to government's role as a landlord and to its role as a general tax collector.

Types of Rent-collecting Systems

Systems for collecting economic rents from petroleum exploitation can be divided into two broad categories, namely, bidding systems and taxes of various types. There is one obvious, fundamental difference between the operation of the two types. Bidding schemes essentially involve voluntary payments made by investors, while tax systems normally involve unilateral government action.

In practice, hybrid schemes are sometimes employed. This is particularly the case with production-sharing agreements. Frequently the split in the shares of profit oil between the investor and the national oil company is subject to bids, with negotiations subsequent between the investor and the host government often leading to modifications to the profit oil split. In many countries work programs are biddable items. Frequently these, too, are amended in negotiations between the investor and government representatives. In recent years, when the investment outlook in the petroleum sector has been highly uncertain, initial bidding of profit oil shares followed by negotiation has become increasingly common.

Bidding Systems

Forms of Bidding Systems

Bidding systems can take various forms. Cash bonus bids are the most common in the United States and Alberta. They are lump-sum payments made at the time the leases are offered. Other possible forms include royalty bidding, net profit-sharing bidding, and work-program bidding. All these forms may be employed in the U.S. Outer Continental Shelf.

The competitive bonus-bidding system favoured in the United States and Canada is frequently advocated because it should not produce any distortions. It is argued that, if there is a high degree of competition in bidding for the rights to exploit petroleum, the size of the bonus bids should reflect the expected economic rents. In effect the interested investors will estimate the Expected Monetary Value (EMV) from the prospect on offer, discount future costs and revenues at their own discount rates, and make their own estimates of the probability of success at the exploration phase. The bids thus reflect the investors' perceptions of the prospects and their own discount rates, rather than the perceptions of outside parties such as host governments. The payments made are entirely voluntary and no subsequent disincentives emerge. From the viewpoint of host governments, the present value of the expected economic rents are received before exploitation commences. The administrative costs of operating the scheme will be small in comparison with those likely to be incurred under a discretionary fiscal system.

Despite the obvious attractions there are problems associated with the widespread application of a bonus-bidding system. A high degree of competition among bidders is required; collusion among investors could thwart the effective operation of the system. The dangers of collusion are less the greater the number of bidders, but in many countries the number of investors interested in acquiring blocs put on offer can be very small. In some Third World countries there have been many cases of only one investor (or two investors forming a joint venture) interested in acquiring rights to particular blocs.

Bonus bids are of course made on *ex ante* perceptions of economic rents. Thus, the more closely anticipations prove correct the more accurate will the system be in collecting economic rents. In practice this means that the better the geological prospectivity is known, and the fewer the uncertainties surrounding oil prices and exploration and extraction costs, the greater the likelihood that bids will reflect the economic rents obtained from petroleum exploitation. There will be many circumstances where *ex post* economic rents diverge from *ex ante* rents. Such differences can arise from unanticipated movements in oil prices and unexpected results of exploration work. A bidding system cannot be expected to extract unanticipated rents accurately.

In many cases where acreage is being made available, the geological knowledge available to investors is extremely limited. This will be the case where "new" geological provinces are being opened up. In these circumstances investors are very likely to put a risk premium on the bids they submit; the greater the uncertainty the bigger the discount is likely to be. It is in this sense that the host government does actually share in the exploration risks under a bidding system. Where geological uncertainty is very high the chances of the bids not reflecting the realized rents are obviously likely to be higher than under a situation where the geological prospects are well known. This actually constitutes an argument for government provision of basic geological knowledge prior to the bidding taking place, in which case the government is, of course, directly bearing the burden of some of the exploration risks and costs.

Experiments were made with royalty bidding in the United States in 1974.[1] It can be argued that royalty bidding has advantages over bonus bidding because, since front-end payments are not required, the advantages of large companies over small ones are eliminated. There should thus be scope for enhanced competition, and thus a greater likelihood that the host government will obtain a high share of the economic rents. Royalty bidding may well introduce distortions, however. The level of bids could be so high that some discoveries are not viable on a post-royalty basis. Similarly, high royalty bids could lead to fields being prematurely abandoned. In the U.S. experiment with royalty bidding in 1974, winning bids ranged from rates of 56.8 per cent to 82.2 per cent.[2] The apparent advantages of royalty bidding in fostering competition among investors could be outweighed by the disincentive effects.

Some of these problems would be avoided by a system of net profit bidding: the disincentive effects must be less under a system based on profits compared with one based on gross revenues. In general the chances of disincentives emerging are certainly less with a profits-based scheme, but problems will still develop. The bidding could still reach such levels that fields discovered subsequent to the bids turn out to be uneconomic. In one case of a drainage sale in California, the winning net profits bid was 95.56 per cent.[3] Adoption of a net-profit-bidding system introduces further complications. The simplicity of the bonus-bidding system is greatly reduced, as the government has to devise a scheme to define net profits for this purpose and this involves issues such as the valuation of petroleum and the appropriate rate of write-off of investment expenditures. The net profit scheme thus introduces many extra complications and costs of implementation, although in many cases the host government will have in place a system of corporate income tax applied to petroleum exploitation, and so these extra costs may not be substantial. The rate of depreciation permitted will affect the profitability of projects to the investor and so introduces the possibility of disincentives emerging.

Work-program bidding can lead to other forms of distortions, in particular a non-optimal amount of exploration taking place. The results of an initial exploration effort could be so disappointing that further seismic or drilling activity is not justified, but obligations already made may require additional expenditures. Some host governments may feel that thorough exploration of a geological province is so important that the extra costs are worthwhile. In general, however, it cannot be said that the system leads to the optimal amount of exploration effort. The other bidding systems are more neutral in this respect. It does not necessarily follow, however, that exploration costs will be minimized under a bonus-bidding system – the winning bidder might have the lowest exploration costs and his success could be due to efficiency, but equally he may have won because he was more optimistic about likely reserves or oil prices.

Empirical Studies of Bidding Systems

The performance of the bidding systems in the United States and Alberta has been subjected to empirical investigation. In a detailed study of the oil and gas leases issued in the Outer Continental Shelf in the Gulf of Mexico between 1954 and 1969, Mead *et al.* found that, of the 1,223 leases issued, nearly 62 per cent proved to be dry. The *average* rate of return on *all* the 1,223 leases was estimated at 13.16 per cent pre-tax and 10.74 per cent on an after-tax basis. It is important to note that the pre-tax returns were calculated after royalty as well as after bonus payments. The average number of bidders per lease was 3.3. The post-tax returns were close to the average after-tax annual return of 11.8 per cent on shareholder equity in U.S. manufacturing in the period 1954-1980. Mead *et al.* conclude that, generally, the lease bidding system has performed efficiently.[4]

The period reviewed by Mead *et al.* (1954-1969) was one in which oil prices behaved in a comparatively stable manner, unlike the experience of the 1970s and 1980s. Dworin and Deakin have argued that, by focusing on pre-1970 leases, the study by Mead *et al.* could not adequately describe the effects of recent changes in oil prices and taxation.[5] Dworin and Deakin's study focuses on 2,515 leases awarded in the Gulf of Mexico in the period 1954-1978. Using Monte Carlo analysis they find that the average pre-tax (but post-bonus and royalty) internal rates of return on leases awarded in the 1970s were very much higher than on those awarded in the period 1954-1969. In some years the estimated returns from leases awarded exceeded 40 per cent, and in many the figure exceeded 35 per cent. Post-tax returns were also much higher for leases awarded in the 1970s and the difference between pre- and post-tax returns was greater. Dworin and Deakin note that their methodology may overstate rates of return somewhat. They also note that positive rates of return were obtained from only 33 per cent of the leases awarded; and in 50 per cent of the cases where positive returns were achieved, the rate was less than 26.7 per cent.[6]

A possible interpretation of these findings is that the bonus-bidding system operated more effectively when the behaviour of oil prices was more predictable. Dworin and Deakin's findings imply that the returns on some leases must have been extremely high on both a post-bonus and a post-tax basis. This would reflect the inability of the bidding system always to collect *ex post* economic rents. In these cases the parties to the auction probably did not correctly anticipate the large rise in oil prices in the 1970s.

Empirical studies of the operation of the bidding system in Alberta have been made by Watkins[7] and Watkins and Kirkby.[8] The studies found that overall the bonus-bidding system ensured that the Alberta government captured a high share of *ex ante* economic rents in both the late 1960s and the late 1970s. They also found, however, that the government did not capture a high share of *ex post* economic rents; the sliding-scale royalty formula was inadequate to collect a high share of the rents generated by unanticipated higher oil prices.

Royalties and Production Taxes

The conventional fiscal devices imposed on oil exploitation activities can produce various types of distortions. The most traditional form of impost has been the royalty; this has traditionally constituted the reward of the landlord for allowing exploitation of a resource which he owns. In a situation where the investor has no control over the market price of his product, conventional royalties and other production-based levies can cause marginal fields to be uneconomic, and can also lead to fields being prematurely abandoned. Conventional royalties and production levies are obviously not well related to profits and so the danger of such distortions emerges.

As profitability of exploitation falls due to lower oil prices or higher exploitation costs, a traditional flat-rate royalty or production tax will take an increasing share of gross profits. In an extreme situation payments have to be made when zero or negative profits are being earned. Because obligation to pay royalties or production tax commences with first production, the burden of these imposts in present-value terms is increased compared with other taxes, liability for which does not commence so early in field life. It follows that in present-value terms the burden of production-based levies is higher than for payments of total comparable size which commence later in field life. The early commencement of liability also increases the share of such payments in the economic rents from field production. When a field becomes marginal the burden of front-end royalty or production-tax payments can readily make a project sub-marginal.

When profitability of exploitation increases due to rising oil prices or unexpectedly low costs, the share of a flat-rate royalty or production tax in gross profits falls. Similarly, the share of economic rents extracted falls. Traditional royalties are thus crude devices which are comparatively insensitive to changes in realized economic rents emanating from oil-price movements or cost variations. In other words flat-rate royalties and production taxes are not efficient instruments with which to collect economic rents.

Investors will generally cease production from a field when net profits turn negative, and the existence of production-based levies can accelerate the timing of this decision. As production falls, exploitation costs eventually exceed revenues; the field is abandoned when marginal cost exceeds marginal revenue. Production-based levies form a wedge between gross revenues and exploitation costs. The requirement of an additional payment based on revenues means that marginal cost exceeds the *net* price at a higher level of output. The field will be abandoned earlier than would otherwise be the case and resources, the exploitation of which is in the national interest, will remain in the ground. For this reason provisions for royalty relief exist in the regulations of many countries.

From the point of view of host governments, royalties and production taxes have some obvious advantages. Early revenues are attractive to all governments, and the likelihood of these continuing throughout field life is also appealing. The costs of monitoring and administering royalties are also less than those for other fiscal devices; for profits-based taxes, for example, information requirements are greater and forecasting revenues is much more difficult. When oil prices and production vary, revenues from royalties also change but not to such an extent as under profits-based systems. Host governments are likely to feel that, compared with most other fiscal devices, royalties and production taxes leave more of the risks of petroleum exploitation with the investor. Under the conventional royalty, cost risks are borne almost entirely by the investor. In particular, the risks of development cost overruns, which have been a major feature of offshore exploitation over the last decade, would be borne by the investor under a conventional scheme. However, royalty systems will not always spread risks to a lesser extent than will profits-based ones. It has been found that when costs and revenues were independent or moved in opposite directions, profits-based systems shared risk to a grater extent than royalties, but when they moved together, risk-sharing could be greater with royalties than with profits taxes.[9]

Many host governments are aware of the crudities of conventional royalties and production taxes and have modified them in order to reduce distortions. Sliding-scale systems (such as those in Australia, Norway, and Alberta), where the rate increases with output, may capture a greater share of the rents from large fields, but the non-deductibility of costs and the continuing insensitivity of the schemes to price changes mean that distortions can still readily arise.

Large fields can be marginal in Norway and Australia and the sliding-scale scheme can exacerbate this problem. The Alberta scheme—where the effective royalty rate is a function of well-production volumes, the oil price, and the time of discovery—is both more sophisticated and complex.[10] The non-deductibility of exploitation costs means, however, that freedom from distortions cannot be guaranteed; situations can readily arise where projects are viable on a pre-royalty basis and unacceptable after these payments; similarly, projects could be prematurely abandoned. When large changes in oil prices take place, discretionary changes to the scheme will also be required if disincentives are to be avoided at "low" prices and if government's share is to be maintained at "acceptable" levels at "high" prices.

The device of the economic-limit factor employed for the production tax in Alaska explicitly recognizes the danger of premature abandonment. This device is ingenious and represents an advance over more conventional sliding-scale systems related to production. Sliding scales will not prevent premature abandonment, as it is the non-deductibility of exploitation costs that is the root of the problem. In this respect the PGRT levied by the Canadian federal government is not likely to cause premature abandonment, as operating costs are allowed as a deduction.

Corporate Income Tax

The effects of conventional income taxes on petroleum investments depend upon the rate of tax and the provisions regarding depreciation, loss offsetting, and any other allowances in the system. The timing of the recovery of investment costs affects the effective burden of the tax because the present value of tax liability is reduced through the depreciation provision; the present value of these tax savings is obviously greater the faster the permitted rate of depreciation. Both the overall time period within which investment costs are depreciated and the rate within this period are relevant in determining the value of tax savings to the investor.

The effective corporate tax burden thus depends upon both the nominal rate of tax and the rate of depreciation: the faster the permitted depreciation the lower will be the effective rate for a given nominal rate. A very fast pace of depreciation helps all investors, but particularly those acquiring long-lived assets, for whom the present value of the tax savings is greater than when the asset is short-lived. For an economically efficient corporate income-tax system, a neutral rate of depreciation is required.

A neutral rate of depreciation is defined as one which does not alter the ranking of attractiveness of projects to investors.[11] In principle this will occur when annual depreciation for tax purposes equals the decline in the value of the asset in question. Over every year of its lifetime the value of an asset equals the capitalized present value of the expected future flow of income. Thus, the fall in its value equals the capitalized value of the fall in the flow of income. In turn this is the appropriate value of economic depreciation which should be employed in determining taxable income – it will ensure that assets that have equivalent net present values bear equal tax burdens as defined by the present value of tax payments. The result of the employment of economic depreciation is that the nominal rate of tax is also the effective rate and the system is neutral between projects of different lives and capital intensities.

In practice, the determination of economic depreciation with regard to petroleum exploitation is, to say the least, very difficult. The required information for every year of the life of a project is the decline in the present value of the cash flows expected over the remainder of its life, but the uncertainties regarding recoverable reserves and oil prices, in particular, make such information extremely difficult to specify with accuracy. The question of the appropriate discount rate to be used is a further major difficulty. The depreciation provision is very sensitive to the choice of interest rate.

Despite these problems, it is worth stating in principle the desirability of a system that is neutral between projects.[12] The systems of write-off for exploration and development costs (including both tangible and intangible items) found in practice can then be examined to see how they are likely to diverge from this benchmark.

One of the least economic mechanisms in the tax system is the depletion allowance. Petroleum exploitation differs from manufacturing industry in the sense that a wasting asset is being exploited. While a manufacturer can replace equipment by new investment, the exploration which is required by an oil company is very risky and will probably not exactly replicate the depleted reserves. A depletion allowance equal to a given percentage of revenues has been justified as an "extra" allowance to reflect the depletion of reserves and thus the decline in net present value. In general this type of allowance is not justifiable on neutrality or equity grounds. It could only be justified on these grounds as a deduction if the gain to the investor from his discovery of petroleum reserves were included as a positive item in taxable income; given that this does not occur, there is no general case for a depletion allowance. Also, an allowance is not a very efficient device to encourage exploration to replace depleting reserves. In short, a depletion allowance provides the investor with extra post-tax income which he can utilize as he sees fit. For example, he could increase dividends to shareholders. This was recognized in Canada, where the depletion provision was adjusted to allow only earned depletion, dependent on exploration and development activity. A fast write-off of exploration costs represents a more direct incentive and is likely to be consistent with economic depreciation.

Under conventional income-tax systems, the timing of the commencement of the utilization of allowances for investment expenditure plays a significant role in determining their impact. In some systems utilization can start as soon as the expenditure is incurred, while in others it has to wait until the asset is placed in service, which in effect means first production from the field to which the expenditure relates. Clearly, the present value of the tax burden is increased under the latter scheme. In offshore situations, where the time lag between investment expenditure and production can be quite long, there is greater ability to utilize allowances relating to the development of a field against income from existing operations. For example, in the U.K. sector of the North Sea just before the 1984 budget changes, the expected rate of return on one representative field was 15.7 per cent on a project basis and 27.1 per cent on an ongoing basis.[13]

The facility to offset the costs of new exploration and development against other existing income by postponing payments of tax reduces the effective cost of developing new fields. In most countries income tax is levied on a company's nationwide activities; so if the legislation permits allowances to be utilized as soon as expenditure is incurred, the investor obtains a useful incentive. In some jurisdictions ring-fence provisions prevail, whereby income-tax assessments are made on a field-by-field or contract-area basis. Indonesia is such a case—a separate company is required for each contract area and no group relief is permitted. This increases the net cost of undertaking new exploration and development work.

The legislation concerning utilization of allowances reflects the extent to which government is sharing in the investment risks. When exploration and development allowances can be set against other income as soon as expenditure is incurred, the government is sharing in the investment risks to a considerable extent. This is the main example of loss offsetting being permitted. If the new expenditure does not generate taxable profits, the government will have lost revenue in absolute terms; if the new expenditure is successful, the government will be suffering a postponement of revenue compared with the situation under a ring-fence arrangement or one where allowances cannot be claimed until the asset is placed in service.

Special Profits-related Taxes

In the main North Sea producing countries (the United Kingdom, Norway, Denmark, and the Netherlands) the governments have imposed special profits-related taxes which are not income taxes in the conventional sense. In the case of the first three countries they are levied on a field-by-field basis. This limits the government's investment risks. At the same time devices such as the "uplift" or extra relief for field capital expenditure are included, in order to relate the government take to field profitability.

While in general such imposts are less likely to cause disincentives than are production taxes or royalties, they do carry inherent risks of creating distortions. The presence of an "uplift" on capital outlays can ensure that the tax burden is progressively related to profits in money-of-the-day terms, but it may not do so in present-value terms. Also, the provision of investment reliefs exceeding 100 per cent of the outlays, combined with high marginal rates of tax, can result in a lack of cost-consciousness or the encouragement of "gold-plating" expenditures. The incentive is similar to the so-called A-J effect sometimes observed in public utilities faced with regulating pricing constraints.[14] In the United Kingdom the ring-fence provisions reduce the dangers in the case of initial field investments, but the problem has certainly existed with incremental investments; the U.K. government changed its rules regarding "uplift" in 1981 because of this issue.

The given objective of this type of tax is to collect a high share of economic rents while maintaining investment incentives. However, the tax is not directly related to field profitability (in present-value terms). Use of the indirect mechanism certainly introduces the risk that the scheme will not ensure that disincentives do not emerge or that government's share of economic rents will be "adequate." These schemes have also been found to be insufficiently flexible to changing oil prices to fulfil their given objectives, and discretionary changes have had to be made by governments. This increases the uncertainty of the investment environment.

Special Excise Taxes

As a device to collect economic rents from rising oil prices, several governments have introduced excise-type taxes based on the difference between a base price and the market valuation. The most famous of these is the Windfall Profits Tax in the United States but others – such as the Excess Proceeds Tax in Malaysia; some forms of levies employed in Australia over the last decade; and one element of the royalty scheme in Alberta – all fall into the same general category. The basic idea behind this type of levy is that oil price increases confer windfall gains on producers, and at least a part of these gains can legitimately be extracted by the state. The tax may commence as soon as production from a field starts if the base price is less than the market price at that time.

This type of levy has several problems associated with it. There are difficulties in determining the base price, both because of qualitative differences in the resources and because of variations in oil prices. In a producing province fields will have differences, possibly wide ones, in exploitation costs; a single base price might leave an investor in one field with adequate returns while in other fields the same price might make the projects uneconomic. With a flat rate of tax the system is always regressive with respect to profits: there will be a larger percentage take from fields of low profitability compared with highly profitable ones. Thus, there is a danger that incentives to develop marginal fields will be impaired, while at the same time the burden on highly profitable projects will be comparatively light.

The scheme could be made more complex or sophisticated in an attempt to deal with these problems. This is certainly the case with the Windfall Profits Tax in the United States, where the rate of tax and the base price vary according to when the fields were discovered; the base price is higher for "new" oil and the tax rate lower. Also, very small projects are exempt from the tax. These modifications can obviously provide incentives to explore, but the mechanism is still crude and could well not achieve its objectives. There could be artificial incentives to define projects as "new" rather than as extensions of "old" ones. Further, not all "old" fields will be of lower cost than "new" ones and there will be variations within the "new" and "old" categories. The rate of levy can to a limited extent be varied according to field size, but fine graduation in this respect is not practicable; furthermore, there is no necessary relationship between size and profitability. Proliferation of the number of different base prices reduces the possibilities of distortions emerging, but this greatly complicates the scheme and increases its costs of operation.

From the point of view of risk sharing, this type of tax leaves the exploration and field development risks with the investor, while the oil price risks are shared between the investor and the government when the market price exceeds the base price. The fact that the tax is reduced to zero when the price falls to the base level gives more "downside" protection to the investor compared with a straight production tax. A risk-averse government will generally be happy with this type of levy, while a similarly inclined investor would probably prefer an income tax.

In sum, it is unlikely that the excise duty levied on the difference between a base and market price can extract economic rents from petroleum exploitation without introducing distorting effects. A simple scheme incorporating only the base price could operate satisfactorily only in a situation where there were no differences in field sizes or costs. To relate the scheme more accurately to the differential economic rents likely to be found in a producing province entails major increases in its complexity. Further, if significant oil price changes take place, discretionary changes might have to be made to the tax rate and the base price. Thus, although this approach has initial attractions, fuller analysis reveals many problems.[15]

Production-sharing Agreements

Though legally quite different in concept, production-sharing schemes have some economic features in common with an income-tax system. Provisions for cost recovery (both regarding any ceilings on the amount of oil available for this purpose and regarding the speed at which costs can be recovered) are akin to allowances for exploration, development, and operating costs. The effects of different rates of recovery are essentially the same as those discussed for depreciation under the income tax.

The overall effect of a production-sharing scheme depends on the share of profit oil taken by government as well as on the cost-recovery terms. For example, "faster" cost recovery can compensate for a "high" profit oil share accruing to government. To obtain neutrality between different petroleum projects, the pace of cost recovery should be the same as for economic depreciation under the income tax. If the ceiling on the share of production is set very low, the investor may not recover all his costs over the lifetime of the field; such a situation would be akin to the imposition of a royalty or production tax.

The profit oil share accruing to government can be likened to the income-tax payments. In early contracts profit oil splits were on a flat-rate basis. In more recent years the split has tended to be on a progressive basis in favour of government, with the state's share increasing incrementally with periodic production. To the extent that economic rents increase with field size an incremental scale ensures that government automatically benefits from large discoveries without having to make discretionary changes to the terms. The incremental scheme should not by itself discourage investors, unless the shares accruing to government become extremely high. The incremental scale is a potentially stabilizing feature of the system which should be beneficial to the investment environment.

An incremental production-sharing scheme is akin to a progressive income tax to the extent that differences in government income accrue from differences in field size. The fact that the progressive scale is on an incremental basis ensures that the marginal rate of "tax" on the investor does not exceed 100 per cent. This reduces the scope for depletion decisions' being distorted by the fiscal package but, if marginal rates rise very steeply, situations could emerge where it would pay the investor to deplete fields more slowly.

The production-sharing system is not geared to deal well with the situation of unexpected changes in economic rents emanating from oil price changes. If the price of oil doubles, the profitability to the investor of a given share of oil would increase considerably; but the fiscal package would not react automatically in such a way as to give the government a large share of such a windfall. If a field were still at a fairly early stage of exploitation and if development costs had not yet been recovered, the result would be that less oil would be required for cost-recovery purposes and more would be available for profit oil sharing. Thus government would share in the gains from the price rise. If the main field development costs had already been recovered, the value of the government's own share of profit oil would be increased from a price rise, but it would not actually receive an increased share of the oil.

If a government adopts a standard form of production-sharing contract throughout is jurisdiction, it might well find that a given structure is appropriate for one area but not for another. Cost conditions can vary considerably within a producing province and a package of given cost-recovery terms and profit oil split could effectively remove the economic rents without causing distortions in one area while leaving large rents or causing disincentives in other areas. A given single scheme would penalize large but very high-cost fields – in relation to pre-tax profitability they could end up having greater tax burdens than low-cost medium or small-sized fields. Of course, a government could vary the terms from one part of the country to another, but this increases the complexity of the regulatory package and probably increases the uncertainty of the investment environment.

Production-sharing contracts are normally designed effectively on a ring-fence basis though the term as such may not be employed. Typically, the exploration and development costs incurred in a contract area may be set against revenues only from the same area. Thus, when exploration in an area starts, commencement of recovery of costs will have to wait until production from that area is attained. This restriction is, of course, taken into account in the design of the provisions for cost recovery and profit oil split.

Production-sharing contracts leave the contractor to take the risks at the exploration and development phases. The government does, however, have an interest in ensuring that these costs are kept to a minimum, because the lower they are the more oil will be available for sharing purposes. When production commences the risks are shared between the two parties.

In sum, production-sharing contracts, especially those incorporating incremental arrangements for profit oil splitting, have some advantages over traditional schemes of royalty and income tax. A given scheme can ensure that governments automatically obtain a high share of the economic rents accruing from fields of many different sizes. If a government is risk-averse, the production-sharing scheme also has attractions. On the other hand this form of agreement cannot ensure that changes in economic rents emanating from changes in the oil price (either upward or downward) will automatically be reflected in changes in government take. Further, a given, single scheme may not be appropriate for fields with large differences in costs.

The "Brown Tax"

Because of the imperfections of all the conventional fiscal devices discussed above, economists have proposed the use of other fiscal instruments in an attempt to obtain a distortion-free mechanism by which economic rents can be collected. The two which have found most favour are the "Brown tax"[16] and the resource rent tax.

The "Brown tax" is based on corporate net cash flows. All exploration, development, and operating costs are recoverable on 100 per cent first-year basis. There are no ring-fence provisions and so all expenditures on new activities can immediately be set against existing income. In effect the government subsidizes exploration and development activities (entailing negative cash flows) at the same (flat) rate that is subsequently applied to positive cash flows from petroleum exploitation. Where the investor has no existing income against which to set expenditures it incurs, the government actually pays a share of the costs to the extent of the tax rate.

This tax, very simple in concept, is neutral in the sense that the post-tax rate of return is not less than the pre-tax one (though post-tax net present values will generally be less than pre-tax values). The scheme shares project risks with government to such a large extent that, statistically, the dispersion of the distribution of outcomes facing investors from new projects is actually reduced. This major "shifting" of investment risk may well be unacceptable to some governments. No tax would be payable if no commercial discovery were made or if exploitation were unprofitable, and the financing of the government's share of costs may prove difficult, especially in Third World countries.

In general the tax has many attractions, not only because of its neutrality, but also because of the comparative ease of obtaining a distortion-free scheme which is automatically adaptable to changing circumstances in the operating environment. The scheme taxes only economic rents, but there is no complicated procedure required by legislators to determine or define rents; for example, no knowledge is required of the investor's discount rate.

Resource Rent Tax

Probably because of the requirement on governments to become full sharers in the front-end investment risks, the "Brown tax" has not been popular among governments. The resource rent tax has been found more acceptable to legislators. In essence this tax allows the investor to achieve a specified (discounted) threshold rate of return on a project before tax becomes payable. The threshold rate of interest is used to compound forward the investor's net cash flows, commencing with initial exploration; the accumulated total becomes a larger and larger negative figure until production commences; and the compounding process continues until the accumulated total becomes positive. The resource rent tax is then levied and continues to be levied on positive annual net cash flows.

In principle the threshold rate should represent the investor's discount rate. If this rate is employed, then the tax should not discourage investment in fields which have already been discovered. Unfortunately, different investors may employ different rates, and any one investor could legitimately employ several, with the chosen one depending on the perceived risks of the project in question. Further, investors will generally not reveal their discount rates to governments. Governments will therefore have to estimate discount rates. If they use rates that are below those employed by investors, projects will be be discouraged; if they employ rates higher than those employed by investors, governments would end up with a lower share of the economic rents than could have been obtained with full knowledge.

If investors' threshold rates are accurately reflected in those enacted in legislation, then economic rents from discovered fields can be collected without disincentives emerging. Marginal field developments, too, would not be impaired. The system would be highly sensitive to fluctuations in oil prices and to ranges of exploitation costs and field sizes. It would automatically react in such a way as to increase government take when profitability increases, from whatever source, and to reduce government take when profitability falls. The sensitivity would be strong enough to ensure that government would always obtain an "adequate" share of the economic rents while field developments would never be deterred when they were viable on a pre-tax basis.

From the investor's viewpoint the resource rent tax has the advantage that capital investment risks are shared with government to a greater extent than under conventional tax systems: until the threshold rate of return is attained no tax is payable; this does not happen with conventional taxes. Risk sharing is unlikely to be as great as it is with the "Brown tax," however, because the resource rent tax is likely to be levied on a contract-area or project basis, not on a company-wide basis. Thus, the investor still has to bear all the initial exploration and development risks prior to production from the project in question.

Resource rent tax schemes can have one or more tiers with positive tax rates. Under a multi-tier scheme the system is progressively related to rates of return. When several tiers exist, care has to be taken to ensure that overinvestment or "gold-plating" incentives are not introduced. In general the danger of such distortions emerging is greater the greater the jump from one threshold rate to the next and the greater the increase in tax rates from one tier to the next.[17]

When exploration risks are brought into the picture, it becomes clear that a resource rent tax could produce disincentive effects at the exploration stage of petroleum exploitation activities. Investors base exploration decisions on calculations of expected monetary values which take into account the probability of discoveries being made. A resource rent tax system, while it might not deter the development of discovered fields that were viable on a pre-tax basis, could still deter exploration. Expected monetary values could be positive on a pre-tax basis and negative post-tax.

The danger of this occurring increases as the probability of making discoveries falls, because the resource rent tax as normally specified does not share in the risks of failure to make commercial discoveries. If the scheme is on a project or contract-area basis, there is no provision for write-off of unsuccessful exploration. Only if the base of the resource rent tax encompassed the whole country in question would risk sharing be "full"; the tax would then be effectively the same as a "Brown tax" for all but the initial investments in the country in question. It has thus to be recognized that a resource rent tax could reduce exploration.[18] It should be emphasized, however, that this type of disincentive is present with *all* conventional tax and royalty schemes.

The Importance of Attitude to Risk

The discussion of the effects of different fiscal instruments has highlighted the question of risk sharing between investors and host governments. In choosing fiscal tools, governments may well give considerable weight to the amount of risk they are prepared to take, and they will have an optimal amount of risk exposure towards petroleum exploitation.[19] They will, of course, also be concerned to minimize the distortions discussed above. This suggests that a combination of a cash-bonus bidding system with some form of resource rent tax could be optimal: the cash bidding system involves no direct risk taking by government; to the extent that rents are not collected by the bidding system they can be extracted later by the resource rent tax.

It has been argued that when the cost of monitoring different contracts is significant,when there is risk aversion on the part of the landowner, when there is the possibility of collusion among bidders, when there is the possibility of asymmetry among bidders regarding information, and when there is a need for comparability among bids, there is a strong case, particularly for private landlords, for employing a sealed-bid auction system plus a fixed royalty rate.[20]

This argument does not apply for many countries, however. Where—as is most common—the government is the landlord, the extra costs of monitoring contracts may be comparatively small, as income-tax legislation will most probably already be in place. Many governments will probably not be noticeably risk averse because exploration risks can be spread over a number of prospects. Furthermore, government may have a social responsibility to ensure that the exploitation of deposits that are viable on a pre-tax basis is not deterred. A combination of a cash bidding system with a form of resource rent tax offers scope for the collection of rents with minimal distortions. In some countries, especially Third World ones, where there are frequently very few bidders for blocs put on offer, reliance on taxation will be more important.

Equity participation by a national oil company is best seen in the context of the optimal amount of risk taking that a government wishes to undertake. The effects of different forms of state participation have been discussed above, particularly with regard to different carried-interest terms. It was shown that all forms of carried interest to some extent act as disincentives to investors. When the state company is a full risk-sharing partner, private investors may still feel a disincentive effect if their preference is for full, independent risk taking. In some circumstances private investors may prefer to have a state company as a partner, not only because of the normal risk-sharing advantages, but also because they may feel that having a state company as a partner provides additional protection; this may be the case in some Third World countries. In general, carried-interest participation does not provide any obvious advantages over a resource rent tax scheme. In fact, the use of a state oil company is difficult to justify on purely fiscal grounds. It can more readily be justified in Third World countries as a means to facilitate the transfer of technology and the building up of expertise in petroleum exploitation.

Notes

1. For a discussion of royalty and net profit-share bidding in the United States in the first half of the 1970s see K.W. Dam, *Oil Resources: Who Sets What, How?* (Chicago: University of Chicago Press, 1976).

2. *Ibid.*, p. 148.

3. *Ibid.*, p. 152.

4. W.J. Mead, D.D. Muraoka, and P.E. Sorensen, "The Effects of Taxes on the Profitability of U.S. Oil and Gas Production: A Case Study of the OCS Record," *National Tax Journal* 35, no. 1 (1982), pp. 21-29. See also W.J. Mead, A. Moseidjord, and P.E. Sorensen, "The Rate of Return Earned by Lessees under Cash Bonus Bidding for Outer Continental Shelf Oil and Gas Leases," *The Energy Journal* 4 (October 1983), pp. 37-51, and W.J. Mead, A. Moseidjord, D.D. Muraoka, and P.E. Sorensen, *Offshore Lands* (San Francisco: Pacific Institute for Public Policy Research, 1985).

5. L. Dworin and E.B. Deakin, "The Profitability of Outer Continental Shelf Drilling Ventures: An Alternative Approach," *National Tax Journal* 36, no. 1 (1983), pp. 57-63.

6. Dworin and Deakin, "Profitability of OCS Drilling Ventures," pp. 60 and 63.

7. G.C. Watkins, "Competitive Bidding and Alberta Petroleum Rents," *The Journal of Industrial Economics* 23, no. 4 (June 1975), pp. 301-12.

8. G.C. Watkins and R. Kirkby, "Bidding for Petroleum Leases: Recent Canadian Experience," *Energy Economics* (July 1982), pp. 182-86.

9. J.K. Sebenius and P.J.E. Stan, "Risk-Spreading Properties of Common Tax and Contract Instruments," *The Bell Journal of Economics* (Autumn 1984), pp. 555-60.

10. See also the discussion in G.C. Watkins and B. Scarfe, "Canadian Oil and Gas Taxation," *The Energy Journal* 6, Special Tax Issue (1985), pp. 17-36.

11. For a detailed discussion of this topic see R.A. Musgrave and P.B. Musgrave, *Public Finance in Theory and Practice*, 4th ed. (New York: McGraw-Hill, 1984), pp. 420-21 and 428-30.

12. A system of economic depreciation may not be neutral between saving and consumption. See R. Garnaut and A. Clunies Ross, *The Taxation of Mineral Rents* (Oxford: Oxford University Press, 1983), p. 104, and P. Swan, "Income Taxes, Profit Taxes and Neutrality of Optimising Decision," *Economic Record* 52, no. 138 (June 1976), pp. 166-81.

13. A.G. Kemp and D. Rose, "U.K. North Sea: Tax Changes in the 1984 Budget," *Petroleum Economist* 51, no. 4 (April 1984), pp. 148-50.

14. See H. Averch and L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* 52, no. 4 (December 1962), pp. 1052-69.

15. For a critical discussion of the problems of the Windfall Profits Tax see J. Blankenship and D.L. Weimer, "The Double Inefficiency of the Windfall Profits Tax on Crude Oil," *Energy Journal* 6, Special Tax Issue (1985), pp. 189-202.

16. See E. Cary Brown, "Business Income Taxation and Investment Incentives," in *Income, Employment and Public Policy: Essays in Honour of Alan H. Hansen* (New York: Norton, 1948).

17. For a detailed discussion of this point see R. Garnaut and A. Clunies Ross, *The Taxation of Mineral Rents* (Oxford: Oxford University Press, 1983), pp. 131-33.

18. This point has been made by several commentators. See, for example, P.G. Bradley, "The Resource Rent Tax in Australia," *The Energy Journal* 6, Special Tax Issue (1985), pp. 37-48.

19. For an illuminating discussion of this subject see B. Smith, "The Taxation of Mineral Rents," paper presented to seminar at the Bureau of Industry Economics, Australia, October 1982. See also B. Smith, "Resource Rent Tax and the Allocation of Mineral Exploitation Rights," in Committee for Economic Development of Australia, *Growth 34: Taxation Reform*.

20. M.S. Robinson, "Oil Lease Auctions: Reconciling Economic Theory with Practice," UCLA Working Paper No. 271, University of California Los Angeles, October 1982.

Chapter 5

Methodology and Assumptions for Empirical Work

The main purpose of this study is to conduct an empirical investigation into the comparative performance of a number of fiscal and quasi-fiscal measures applied to petroleum exploitation. The jurisdictions examined are Australia, the United Kingdom, Norway, Indonesia, Malaysia, China, Egypt, Nigeria, the U.S. Outer Continental Shelf, Alaska, Texas, Alberta, and Canada Lands. The methodology employed follows directly from the discussion of petroleum rents in Chapter 2. Economic rents are measured at the times when the two key decisions are being made, namely, (a) to develop discovered fields, and (b) to engage in a program of exploration. At the time of the development decision, gross economic rents are measured by the prospective pre-tax net present value from the field in question. On the revenue side the potential economic rents accruing to the whole nation are best measured by valuing oil at its free-market level.

The discount rate employed to calculate the net present value is in principle the rate that reflects the particular country's time preferences and attitudes to risk. Where a government has decided that petroleum exploitation with its associated risks is to be undertaken by private industry, the appropriate discount rates will be those chosen by the oil companies. Governments can, of course, still influence the values of such discount rates by the legislative environment they establish. Where exploitation is via state corporations, social discount rates are appropriate. Where private and state investors are partners, conflicts can emerge in this respect; an example is Norway, where disputes have recently emerged about the viability of new fields.[1] In public discussions of the subject of petroleum developments, the Norwegian authorities have consistently employed a discount rate of 7 per cent in real terms but, as was discussed in Chapter 2, oil companies generally employ higher rates. This study has employed a range of discount rates from 5 to 20 per cent in real terms. This permits a wide range of time preferences and attitudes to risk to be incorporated.

The analysis has been conducted by simulating the investment environment with the aid of a set of computerized financial models. These incorporate the fiscal instruments employed to remove the economic rents in the different countries. The models initially calculate the pre-tax rents and fiscal takes in money-of-the-day terms, as taxes are paid on this basis. Subsequently real values and discounted real values are calculated, with 1986 being the base year.

The simulations were carried out on a suite of hypothetical fields designed to reflect the range of operating circumstances in the various jurisdictions.

A brief description of the operating environment in the offshore situations examined in this study is given in Appendix 5.1.

Summary details of the model fields employed for the North Sea environment are shown in Appendix 5.2. The range of sizes is from 2 billion barrels to 50 million barrels of recoverable reserves. The larger sizes are unlikely to be found in the U.K. sector but there are still prospects for finding fields of a billion barrels or more in the Norwegian sector. In the British sector the most likely sizes of new fields are now 100 million barrels and less. The total lifetime field exploitation costs of North Sea fields being developed now in the U.K. sector are on average around $14 per barrel (at 1985 prices) according to official estimates;[2] this includes a 10 per cent real rate of return on investment. In terms of the model fields this approximates to the Medium Cost (MC) range in Appendix 5.2. In the Norwegian sector cost conditions are generally reckoned to be higher than in the U.K. sector. A range of unit costs is to be expected. Fields lying in close proximity to existing pipelines will be considerably cheaper than those requiring dedicated pipelines. Moreover, because of economies of scale in developing and operating fields, the unit costs of larger fields are generally lower than those of smaller ones. In terms of the model fields shown in Appendix 5.2, this means that if a small field were in the HC band, a large field in the same geographic location could be closer to MC conditions.

Summary details of the model fields employed for Australia, Indonesia, Malaysia, China, Egypt, Nigeria, Alaska, and the U.S. Outer Continental Shelf are shown in Appendix 5.3. It should be emphasized that the wide range of field sizes and costs certainly does not apply to all countries. In Australia the most likely sizes of fields are in the 50- to 100-million-barrel range; cost conditions will frequently be around the LC mark, but can range up to MC levels. In Indonesia the most likely sizes of fields are also in the range of 50 to 100 million barrels, with LC conditions predominating. This is also the situation in Malaysia, though there are also significant chances of finding fields up to 250 million barrels in that country. In China the most likely sizes of fields are in the range 50 to 100 million barrels with some hopes of larger ones; LC conditions are obtainable in some areas of the Chinese Shelf but in the deeper waters and those some distance from land MC conditions will be experienced. In Egypt fields in the 50 to 100 million barrel range are likely to be predominant, with LC conditions generally attainable. In Nigeria fields of around 50 million barrels are likely to dominate, with LC conditions.

In Alaska (onshore and offshore including the U.S. Continental Shelf) there are still high possibilities of finding very large fields. The costs of exploiting petroleum located in the North of Alaska are extremely high when pipeline transport costs are included; *excluding* the pipeline costs, exploitation costs are approaching the MC level.[3] For situations in offshore California and the Gulf of Mexico, field sizes in the range of 50 to 250 million barrels are likely with some possibilities of larger fields; generally, LC conditions should prevail but in deeper waters higher costs are experienced.

A summary of the model fields developed for Alberta and the Canada Lands is given in Appendix 5.4. The operating environment in Alberta is, of course, very different from that in offshore territories. Fields of 51.7 thousand, 5.06 million, and 31.2 million barrels of recoverable reserves are considered; MC conditions are perhaps the most likely, but a wide range of cost conditions is considered to reflect the possible variations and to incorporate marginal field situations. On the Canada Lands the size and cost conditions of fields can vary greatly, depending on their location. For the Mackenzie Delta (onshore) a base field size of 100 million barrels of recoverable reserves has been considered, and larger and smaller sizes, of 200 and 75 million barrels, have also been employed; the MC range of cost conditions applies, the MC situation shown in Appendix 5.4 indicating the best estimate. For the Beaufort Sea, the base field size has recoverable reserves of 550 million barrels, but variations of 730 and 380 million barrels are also examined; a range of cost conditions is employed, with the MC situation (described in Appendix 5.4) again reflecting the best estimate. For the Atlantic Ocean, the base field size examined has recoverable reserves of 300 million barrels; variations of 665 and 200 million barrels are also employed in the analysis; the MC situation described in Appendix 5.4 reflects the best estimate of costs.

The main features of the model fields employed for West Texas are shown in Appendix 5.5 Two field sizes, with recoverable reserves of 2.25 million barrels and 540 thousand barrels, respectively, have been chosen; the most likely costs are those represented by MC conditions.

The volume of recoverable reserves is not independent of the operating environment. The financial models operate in such a way that a field is abandoned when net cash flows become negative. Thus, recoverable reserves are higher the lower the exploitation costs and the higher the oil price. Some types of fiscal systems, particularly those incorporating production-based elements, can cause fields to be abandoned prematurely.

To analyze the position at the exploration stage it is necessary to simulate expended monetary values. The first step in this process was to determine likely distributions of fields in nature in the various jurisdictions, and this in turn involved consideration of both field sizes and cost conditions. The distributions were chosen on the basis of publicly available information and for some countries with the advice of a major oil company. Details are shown in Appendix 5.6. The next step was to determine the overall probability of making a discovery of any type. Information on this subject is very variable across countries, and it was decided to examine several possibilities ranging from 1 in 2 to 1 in 20. Finally, to find the EMV, the weighted sum of the net present values from the expected fields was calculated, a further weighting made for the overall probability of making a discovery, and the exploration costs deducted from the total. The exercise was conducted for a number of sizes of exploration programs. To take account of the cut-off question discussed in Chapter 2, only fields offering a real return of at least 10 per cent were included in the calculation. This procedure was adopted for both pre-tax and post-tax situations. The only exception was in Norway, where a prospective field was kept in the calculation if it offered a real return of at least 5 per cent. The reasons for this are as discussed above in connection with the development decision.

The exercise was conducted for a variety of exploration costs to reflect the range of circumstances likely to be encountered in each of the countries. An exploration program including seismic and drilling obligations is part of many agreements between investors and host governments. In any one country exploration costs may vary considerably with geography, depending, for example, on whether the work takes place onshore or offshore. In the latter case the costs vary considerably with water depth.

To assess the performance of the fiscal systems applied by governments, it is instructive to examine their behaviour under a variety of oil prices, field sizes, and cost conditions. This study has considered four oil price scenarios, in order to reflect a range of possible outcomes and, in particular, to permit comparisons of 1985 and 1986 perspectives. Three are scenarios that, in 1985, would have been considered likely for 1986 and beyond; based on a world price of $27 for 1986, they respectively project conditions of constant real prices, real prices falling at 2 per cent per year, and real prices rising at 2 per cent per year. The fourth scenario takes account of the collapse in oil prices and is based on a world price of $17 in 1986, $20 in 1987 and 1988, and constant real thereafter. The various scenarios are not forecasts but are intended to show how the fiscal systems behave under different conditions and in relation to movements over a wide range. The world rate of inflation is assumed to be 5 per cent, and petroleum development and operating costs are assumed to escalate at the same pace as general inflation.

The fiscal systems facing investors are described in Chapter 3, in which the systems applicable to new investments in conventional oil are examined. In several countries there are material differences between the regimes applied to "old" and "new" fields. Investments can be viewed either on a project, stand-alone basis or on an ongoing basis. "Stand alone" means that the project is assessed as an independent entity irrespective of the overall tax position of the investor; by contrast, "ongoing" takes account of any immediate benefits from tax deductions that the investor can enjoy. Frequently there is a considerable difference in the tax position resulting from these two views. When an investor has existing income and is able to utilize allowances relating to the development of new fields against that existing income before production from the new field commences, the consequence is that tax payments are postponed. Put another way the government is sharing in the initial investment costs of the new field. With this facility the post-tax return to the investor is greater than on a project, stand-alone basis. In this study the most likely situation under current conditions has been chosen. Where petroleum exploitation is a well-established activity in a territory, the investor is assumed to be in a position to enjoy the fiscal advantages of ongoing operations.

In Chapter 6, where the results of the empirical work are shown and discussed, government takes at different discount rates are expressed as percentages of the gross economic rents, which are defined as the pre-tax net present values at the different discount rates. Sometimes takes are discussed in money-of-the-day terms to elucidate the behaviour of a particular system. These takes are expressed as a percentage of the resources generated from the project in question, which means the total revenues minus total costs.

Notes

1. See *Petroleum Economist* (February 1986), p. 38, and *Petroleum Economist* (March 1986), p. 89. See also *Financial Times*, March 15, 1986, p. 3 (report that Phillips Petroleum relinquished a 25.87% stake in a gas condensate field scheduled for development).

2. United Kingdom, Department of Energy, *Development of the Oil and Gas Resources of the UK, 1987* (London: Her Majesty's Stationery Office, 1987), p. 62.

3. The exploitation costs developed in this study are generally compatible with those cited in M. Berman, E. Myers, W. Nebesky, K. White, and T. Hull, *Alaska Petroleum Revenues: the Influence of Federal Policy*, Institute of Social and Economic Research, University of Alaska, October 1984, Appendices, pp. B25 - B39. See also U.S., Congress, Congress Office of Technology Assessment, *Oil and Gas Technologies for the Arctic and Deepwater* (Washington, D.C.: Government Printing Office, May 1985).

Appendices

Appendix 5.1
Environmental Conditions in Major Offshore Provinces

Country	Total Area of Offshore Provinces to 200 m Water Depth (*million hectares*) (Typical Design Wave Height) (*metres*)	Representative Water Depths (*metres*)		Water Depths		Weather Conditions and Max. Distance (*kilometres*) to 200 m Water Depth or Sector Limit	
				Current production (*metres*)	Maximum exploration (*metres*)		*km*
W. Europe							
United Kingdom	47 (20-35)	North Sea sector	30-200	<50-187	1370	Severe	300
		Celtic Sea	50			Severe	70
Norway	30 (20-35)	North Sea sector	30-200	<50-146	407	Severe	280
		Norwegian Sea	100-500			Severe, ice hazards	20-50
USA							
Alaska	110 (20-30)	Beaufort Sea	<100	-	<30	Severe, year-round ice cover in areas	65
		Bering Sea	<100	-	-	Severe, ice hazards	1200
		Gulf of Alaska	<200	-	<200	Moderate	270
Pacific	6 (20)	<200 and deepwater prospects		<50-260	425	Favourable	50
Gulf of Mexico	28 (15-25)	Generally <100 but also much deeper tracts		<10-312	655	Favourable but violent cyclonic storms	110
Atlantic	10 (30)	Most prospects deep and very deep water		-	1676	Severe to moderate	200
Canada							
Beaufort Sea and Arctic Islands	65 (20)	Most prospects <100 but some very deep water fields in Arctic Islands		-	-	Beaufort – severe, ice cover most of year	150
						Arctic Islands – very severe, multi-year permanent ice cover	10-100

Canada (cont'd)						
Hudson Bay	131	Shallow but no prospects identified	-	<200	Severe, permanent ice hazards in some areas	550
Eastern Seaboard	57 (35)	<200 and deepwater prospects	(90)	1486	Severe, iceberg hazard	375
West Coast	24 (20)	<200, no exploration to date	-	-	Moderate	30-100
Africa						
Egypt	7 (15)	Gulf of Suez <100	15-90	<200	Favourable	25
		Red Sea – deepwater prospects	-	555	Favourable	
		Mediterranean <100	-	<200	Favourable	
Nigeria	7 (10)	<50	5-30	<200	Tropical, favourable	60
Far East and Australia						
Australia	147 (15-25)	Generally less than 150	50-100	1373	Favourable to moderate	
Indonesia	133 (10-20)	Generally <100 but many deeper prospects	15-50	<200	Favourable but typhoons	
Malaysia	24 (10-20)	Generally <100	30-80	<200	Favourable but typhoons	
CPEs						
China	143 (10-20)	Anticipated <200	<30	<200	Moderate to favourable but with frequent typhoons	

Source: Atkins Planning and Scottish Development Agency, *A Review of International Offshore Oil and Gas Markets*, (Aberdeen: Scottish Development Agency, October 1984), pp. 49-52.

Appendix 5.2
Model Oil Fields for the North Sea

1. Size of Recoverable Reserves

Field A = 2 billion barrels = Very Very High Volume (VVHV)
Field B = 1 billion barrels = Very High Volume (VHV)
Field C = 500 million barrels = High Volume (HV)
Field D = 250 million barrels = Medium Volume (MV)
Field E = 100 million barrels = Low Volume (LV)
Field F = 50 million barrels = Very Low Volume (VLV)

2. Size of Development Costs (1986 values)

$3.00 per barrel produced = Low Cost (LC)
$6.00 per barrel produced = Medium Cost (MC)
$9.00 per barrel produced = High Cost (HC)
$11.00 per barrel produced = Very High Cost (VHC)

3. Composition of Development Costs

	Drilling Costs as Percentage of Total Development Costs
Field A (VVHV)	17
Field B (VHV)	18
Field C (HV)	20
Field D (MV)	25
Field E (LV)	25
Field F (VLV)	30

Appendix 5.2 (Cont'd)

4. Phasing of Development Expenditure (Real Terms)[a]

Time Period (Year)	*Percentage of Total Drilling Cost*						*Percentage of Total Capital Expenditure*[b]					
	VVHV	VHV	HV	MV	LV	VLV	VVHV	VHV	HV	MV	LV	VLV
1							1	1	1	1	1	2
2							1	1	1	1	1	6
3							7	7	7	7	7	15
4							21	21	21	21	21	25
5	6	6				10	30	30	30	30	30	30
6	8	8	7	10	12	27	24	24	24	24	24	22
7	14	14	14	20	25	27	16	16	16	16	16	
8	15	15	14	20	25	26						
9	10	10	14	20	25	10						
10	10	10	14	20	13							
11	10	10	14	10								
12	10	10	14									
13	7	7	9									
14	5	5										
15	5	5										

5. Operating Costs (as per cent of Accumulated Development Costs)

	LC	*MC*	*HC*	*VHC*
VVHV	3.5	4.0	4.5	5.0
VHV	4.5	5.0	5.5	6.0
HV	5.5	6.0	6.5	7.0
MV	6.0	6.5	7.0	7.5
LV	8.0	8.5	9.0	9.5
VLV	10.0	10.5	11.0	11.5

6. Production Profiles

Field	*Build-up to Peak Output (years)*	*Plateau Output (b/d)*
A (VVHV)	4	520,000
B (VHV)	4	262,000
C (HV)	3	140,000
D (MV)	2	82,500
E (LV)	2	42,500
F (VLV)	1	25,000

[a] Annual drilling costs are a minimum of $20 million except at the beginning and end of drilling programs.

[b] Total Capital Expenditure excludes drilling.

Appendix 5.3

Model Oil Fields for the World Outside the North Sea, Alberta, Texas, and Canada Lands (Offshore Situations)

1. Size of Recoverable Reserves

Field A = 2 billion barrels = Very Very High Volume (VVHV)
Field B = 1 billion barrels = Very High Volume (VHV)
Field C = 500 million barrels = High Volume (HV)
Field D = 250 million barrels = Medium Volume (MV)
Field E = 100 million barrels = Low Volume (LV)
Field F = 50 million barrels = International Very Low Volume (IVLV)

2. Size of Development Costs (1986 values)

$3.00 per barrel produced = Low Cost (LC)
$6.00 per barrel produced = Medium Cost (MC)
$9.00 per barrel produced = High Cost (HC)
$11.00 per barrel produced = Very High Cost (VHC)

3. Composition of Development Costs

	Drilling Costs as Percentage of Total Development Costs
Field A (VVHV)	17
Field B (VHV)	18
Field C (HV)	20
Field D (MV)	25
Field E (LV)	25
Field F (IVLV)	30

Appendix 5.3 (Cont'd)

4. Phasing of Development Expenditure (Real Terms)[a]

Time Period (Year)	*Percentage of Total Drilling Cost*						*Percentage of Total Capital Expenditure*[b]					
	VVHV	VHV	HV	MV	LV	IVLV	VVHV	VHV	HV	MV	LV	IVLV
1							9	9	9	9	9	23
2							21	21	21	21	21	25
3	6	6				10	30	30	30	30	30	30
4	8	8	7	10	12	27	24	24	24	24	24	22
5	14	14	14	20	25	27	16	16	16	16	16	
6	15	15	14	20	25	26						
7	10	10	14	20	25	10						
8	10	10	14	20	13							
9	10	10	14	10								
10	10	10	14									
11	7	7	9									
12	5	5										
13	5	5										

5. Operating Costs (as per cent of Accumulated Development Costs)

	LC	*MC*	*HC*	*VHC*
VVHV	3.5	4.0	4.5	5.0
VHV	4.5	5.0	5.5	6.0
HV	5.5	6.0	6.5	7.0
MV	6.0	6.5	7.0	7.5
LV	8.0	8.5	9.0	9.5
IVLV	10.0	10.5	11.0	11.5

6. Production Profiles

Field	*Build-up to Peak Output (years)*	*Plateau Output (b/d)*
A (VVHV)	4	520,000
B (VHV)	4	262,000
C (HV)	3	140,000
D (MV)	2	82,000
E (LV)	2	42,500
F (IVLV)	2	15,000

[a] Annual drilling costs are a minimum of $20 million except at the beginning and end of drilling programs.

[b] Total Capital Expenditure excludes drilling.

Appendix 5.4
Model Oil Fields for Canada

Alberta

1. **Size of Recoverable Reserves**

Field A = 31.2 million barrels = High Volume (HV)
Field B = 5.06 million barrels = Low Volume (LV)
Field C = 51.7 thousand barrels = Low Low Volume (LLV)

2. **Development and Completion Costs**

Field	*Costs* (thousands of CAN$ (1984) per well) Low Cost (LC)	Medium Cost (MC) (best estimate)	High Cost (HC)
A (HV)	978	1220	1460
B (LV)	630	784	940
C (LLV)	760	1002	1115

VHC and VVHC estimates are, respectively, twice and three times the MC figures.

3. **Operating Costs**

CAN$43,400 (1984) per well. Operating costs are modified at the same rate as development costs to reflect the range of possibilities.

4. **Production Profiles**

Maintenance of peak production per well for eight years followed by 10% p.a. decline.

Initial Production

Field A (HV): 175 b/d for each of 30 wells.
Field B (LV): 85 b/d for each of 10 wells.
Field C (LLV): 10 b/d for one well.

Appendix 5.4 (Cont'd)

Canada Lands

A. Mackenzie Delta (Onshore)

1. Size of Recoverable Reserves

Field A = 200 million barrels = High Volume (HV)
Field B = 100 million barrels = Medium Volume (MV)
Field C = 75 million barrels = Low Volume (LV)

2. Development Costs

Field	*Medium Cost* (MC)	
A (HV)	c. US$3.50 (1986) per barrel	
B (MV)	c. US$4.50 (1986) per barrel	
	Drilling and Completion	CAN$253.8 million (1985)
	Total	CAN$580 million (1985)
C (LV)	c. US$5.10 (1986) per barrel	

Sensitivity analysis on costs ±30%.

3. Operating Costs

Field	*Medium Cost* (MC)
A (HV)	5% of total development costs
B (MV)	CAN$27.8 million (1985) for most of field life
C (LV)	5% of total development costs

Sensitivity analysis on costs ±30%.

4. Production Profiles

Field	*Plateau Output* (b/d)
A (HV)	45,686 for five years
B (MV)	22,840 for five years
C (LV)	17,132 for five years

Decline Rate: Harmonic decline (c. 18% in early years after plateau to c. 5% in late years of life).

5. Tariff

Field B (MV): Falling over a 30-year period from CAN$16.50 (1985) per barrel to CAN$3.70 (1985) per barrel.

Appendix 5.4 (Cont'd)

B. Beaufort Sea

1. Size of Recoverable Reserves

Field A = 730 million barrels = High Volume (HV)
Field B = 500 million barrels = Medium Volume (MV)
Field C = 380 million barrels = Low Volume (LV)

2. Development Costs

Field	*Medium Cost* (MC)	
A (HV)	c. US$4.00 (1986) per barrel	
B (MV)	c. US$4.50 (1986) per barrel	
	Development Drilling	CAN$273.6 million (1986)
	Island Construction and Production Facilities	1502.8 million
	Pipeline and Gathering Line (offshore)	332.2 million
	Pipeline (onshore)	1200.0 million
C (LV)	c. US$5.00 (1986) per barrel	

Sensitivity analysis on costs ±30%.

3. Operating Costs

Field	*Medium Cost* (MC)
A (HV)	Same percentage of total development costs as on MV field
B (MV)	CAN$179 million per year
C (LV)	Same percentage of total development costs as on MV field

Sensitivity analysis on costs ±30%.

4. Production Profiles

Field	*Plateau Output* (b/d)
A (HV)	150,000 for c. six years
B (MV)	100,000 for c. six years
C (LV)	70,000 for c. six years

Decline Rate: c. 10% per year.

Appendix 5.4 (Cont'd)

C. Atlantic Ocean

1. Size of Recoverable Reserves

Field A = 665 million barrels = High Volume (HV)
Field B = 300 million barrels = Medium Volume (MV)
Field C = 220 million barrels = Low Volume (LV)

2. Development Costs

Field	*Medium Cost* (MC)	
A (HV)	c. US$4.50 (1986) per barrel	
B (MV)	c. US$5.00 (1986) per barrel	
	Development Drilling	CAN$291.2 million (1985)
	Total	CAN$2 billion (1985)
C (LV)	c. US$6.00 (1986) per barrel	

Sensitivity analysis on costs ±30%.

3. Operating Costs

Field	*Medium Cost* (MC)
A (HV)	5% of total development costs
B (MV)	CAN$7.00 (1985) per barrel
C (LV)	5% of total development costs

Sensitivity analysis on costs ±30%.

4. Production Profiles

Field	*Plateau Output* (b/d)
A (HV)	140,000
B (MV)	70,000
C (LV)	46,667

Decline Rate: 15% per year.

5. Tariff

Field B (MV): CAN$4.00 (1985) per barrel.

Appendix 5.5
Model Fields for West Texas

1. **Size of Recoverable Reserves (Pre-Tax)**

Field A = 2.25 million barrels = High Volume (HV)
Field B = 540 thousand barrels = Low Volume (LV)

2. **Development Costs per barrel** (1986 values)

	Low Cost (LC)	*Medium Cost (MC)*	*High Cost (HC)*
Field A (HV)	2.59	3.24	3.91
Field B (LV)	4.63	5.83	7.08

3. **Operating Costs**

	Low Cost (LC)	*Medium Cost (MC)*	*High Cost (HC)*
Field A (HV)	1.36	1.62	1.82
Field B (LV)	3.53	4.20	4.79

Appendix 5.6
Ratios in Nature

Field Type	*Probability*
Australia	
MV/LC	.15
LV/LC	.15
IVLV/LC	.20
LV/MC	.20
IVLV/MC	.20
LV/HC	.05
IVLV/HC	.05
U.K.	
VLV/MC	.20
MV/HC	.10
LV/HC	.20
VLV/HC	.20
LV/VHC	.15
VLV/VHC	.15
Norway	
VHV/HC	.05225
HV/HC	.06
MV/HC	.07
LV/HC	.0711
VLV/HC	.08
VHV/VHC	.05225
HV/VHC	.06
MV/VHC	.07
LV/VHC	.0711
VLV/VHC	.08
VHV/MC	.05225
HV/MC	.06
MV/MC	.07
LV/MC	.0711
VLV/MC	.08
Indonesia	
MV/LC	.10
LV/LC	.20
IVLV/LC	.20
MV/MC	.10
LV/MC	.20
IVLV/MC	.20
Malaysia	
MV/LC	.10
LV/LC	.20
IVLV/LC	.20
MV/MC	.10
LV/MC	.20
IVLV/MC	.20
China	
MV/LC	.10
LV/LC	.25
IVLV/LC	.25
MV/MC	.10
LV/MC	.15
IVLV/MC	.15
Egypt	
LV/LC	.25
IVLV/LC	.25
LV/MC	.25
IVLV/MC	.25
Nigeria	
LV/LC	.25
IVLV/LC	.25
LV/MC	.25
IVLV/MC	.25
U.S. OCS	
HV/LC	.075
MV/LC	.10
LV/LC	.15
IVLV/LC	.175
HV/MC	.075
MV/MC	.10
LV/MC	.15
IVLV/MC	.175

Appendix 5.6 (Cont'd)

Field Type	*Probability*
Alaska	
North[a]	
VHV/LC	.075
HV/LC	.125
VHV/MC	.075
HV/MC	.125
MV/MC	.20
VHV/HC	.075
HV/HC	.125
MV/HC	.20
South	
VHV/LC	.025
HV/LC	.075
MV/LC	.1083
LV/LC	.125
VHV/MC	.025
HV/MC	.075
MV/MC	.1083
LV/MC	.125
VHV/HC	.025
HV/HC	.075
MV/HC	.1083
LV/HC	.125
West Texas[b]	
HV/LC	.125
LV/LC	.125
HV/MC	.25
LV/MC	.25
HV/HC	.125
LV/HC	.125
Alberta[c]	
HV/LC	.06668
HV/MC	.13336
HV/HC	.06668
HV/VHC	.03333
HV/VVHC	.03333
LV/LC	.06668
LV/MC	.13336
Alberta (Cont'd)	
LV/HC	.06668
LV/VHC	.03333
LV/VVHC	.03333
LLV/LC	.083
LLV/MC	.167
LLV/HC	.083
Canada Lands[d]	
Mackenzie Delta (Onshore)	
HV/LC	.0625
HV/MC	.125
HV/HC	.0625
MV/LC	.125
MV/MC	.25
MV/HC	.125
LV/LC	.0625
LV/MC	.125
LV/HC	.0625
Beaufort Sea	
HV/LC	.0625
HV/MC	.125
HV/HC	.0625
MV/LC	.125
MV/MC	.25
MV/HC	.125
LV/LC	.0625
LV/MC	.125
LV/HC	.0625
Atlantic Ocean	
HV/LC	.0625
HV/MC	.125
HV/HC	.0625
MV/LC	.125
MV/MC	.25
MV/HC	.125
LV/LC	.0625
LV/MC	.125
LV/HC	.0625

a. Including transport costs *only* to Prudhoe Bay-Valdez Pipeline.
b. Costs and sizes of fields are different from those in other countries.
c. Costs and sizes of fields are different from those in other countries.
d. Costs and sizes of fields are different from those in other countries.

Chapter 6

Results of Empirical Analysis

In this chapter the results of the empirical analysis of the effects of the different fiscal devices applied to petroleum exploitation are discussed. These results reflect the methodology outlined in Chapter 5. The analysis examines the performance of the fiscal devices at both the new field development and the exploration stages of the decision-making process. The economic rents becoming available are measured under the four oil price scenarios and the field size and cost conditions discussed in Chapter 5.

The investor's tax position considered is that which is most representative at the time of the decision making in the country concerned. If petroleum exploitation in a country has existed for some time, it is presumed that the typical investor is in an ongoing tax-paying position and is able to obtain the benefits of reliefs for new expenditures against existing income. This is likely to be the case in most of the jurisdictions considered here, with China being a notable exception. Reliefs available in the parent country of the investor are not considered here, as these vary considerably with different parent countries, and including them would greatly extend the scope of the study.

The pre-tax position facing an investor contemplating the development of discovered fields in Australia, Indonesia, Malaysia, China, Egypt, Nigeria, and U.S. OCS (California) is shown in Figure 6.1 in the form of net present values at a real discount rate of 10 per cent for different field sizes and cost conditions. These indicate the prospective gross economic rents. The position is shown for two oil

Figure 6.1
International Fields
Real Net Present Values, 10% Real Discount Rate (no taxes)

A. Constant Real Oil Price ($27)

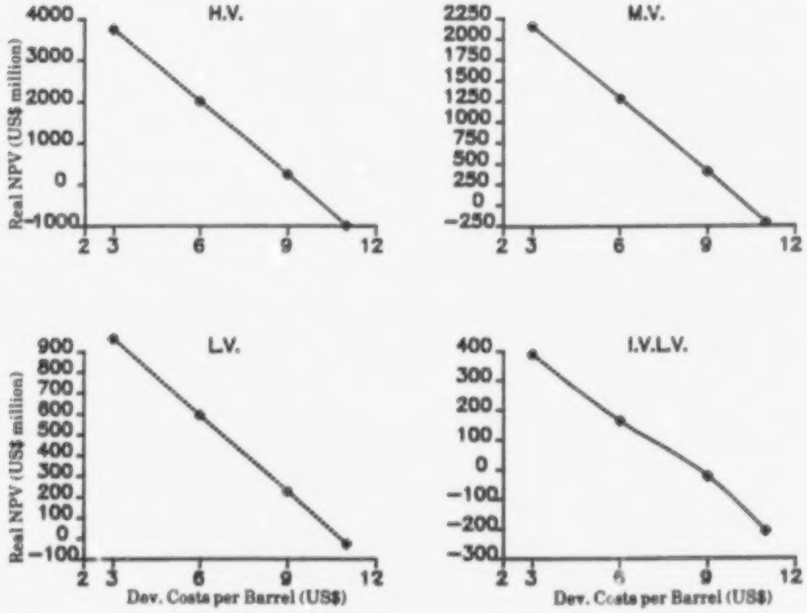
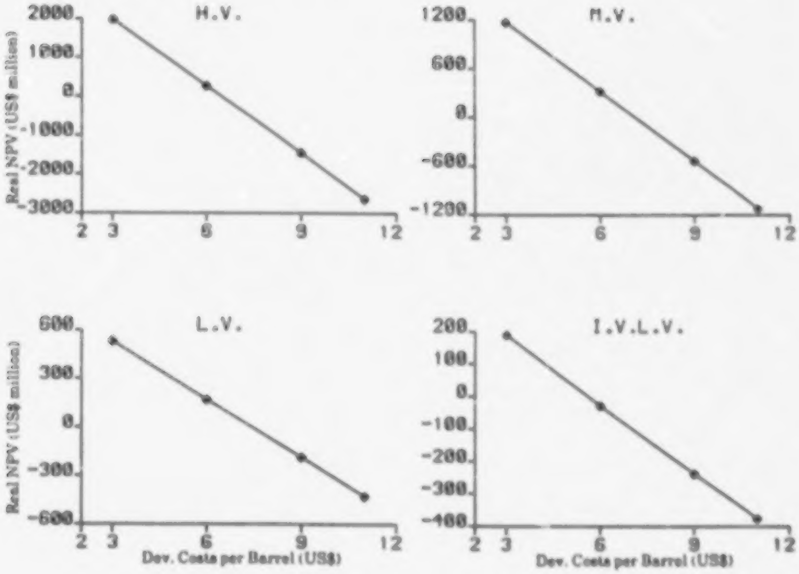


Figure 6.1 (continued)

B. Collapsed Real Oil Price



price scenarios – a constant real price of $27 per barrel (reflecting one possible anticipated position in 1985) and the collapsed-price scenario described in Chapter 5 (reflecting a possible anticipated position in 1986). The dramatic effect of the fall in oil prices on investors' returns is clearly seen by comparing the two sets of results. It is noteworthy that under the scenario of collapsed oil prices all field sizes – except the IVLV one – produce positive returns at a 10 per cent discount rate under MC conditions. At a 15 per cent discount rate under the collapsed price (not shown in Figure 6.1), all field sizes have positive net present values under LC conditions but only the MV and LV fields have positive returns under MC conditions.

The pre-tax net present values at 10 per cent real discount rate for fields exploited under North Sea conditions are shown in Figure 6.2. The figures are different from those shown in Figure 6.1, because rather longer lead times are experienced in North Sea conditions; also the VLV field has a higher plateau output reflecting the producing systems normally installed in the North Sea. At a 10 per cent real discount rate all field sizes yield positive returns with the $27 constant real price under MC conditions, but all are substantially negative under VHC circumstances. At a 15 per cent discount rate (not shown) the MV, LV and VLV fields yield positive returns under MC conditions with the collapsed oil price.

Figure 6.2
North Sea Fields
Real Net Present Values, 10% Real Discount Rate (no taxes)

A. Constant Real Oil Price ($27)

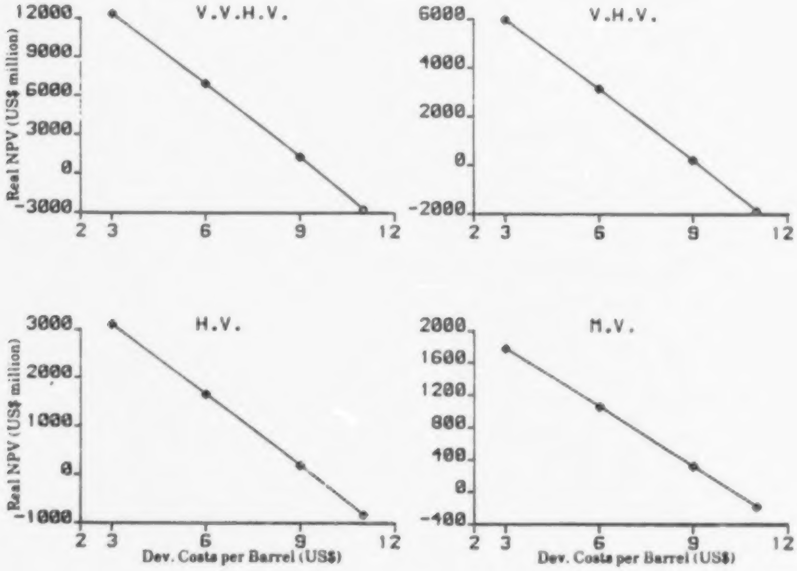
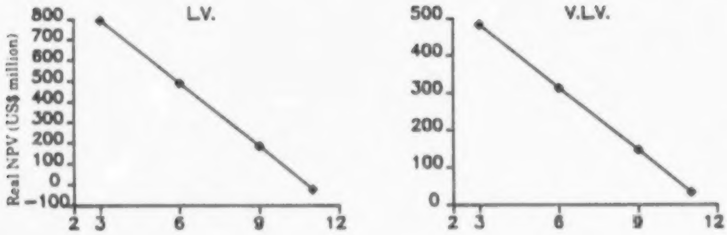


Figure 6.2 (continued)

A. Constant Real Oil Price ($27) - cont'd



B. Collapsed Real Oil Price

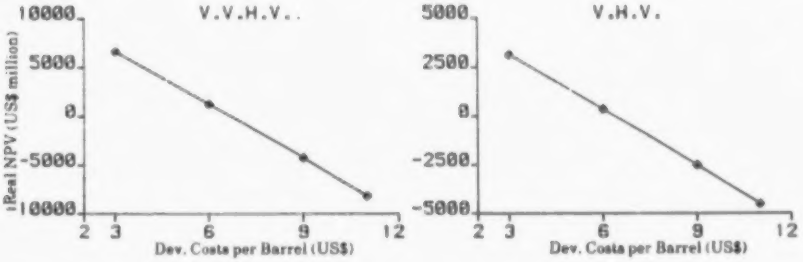
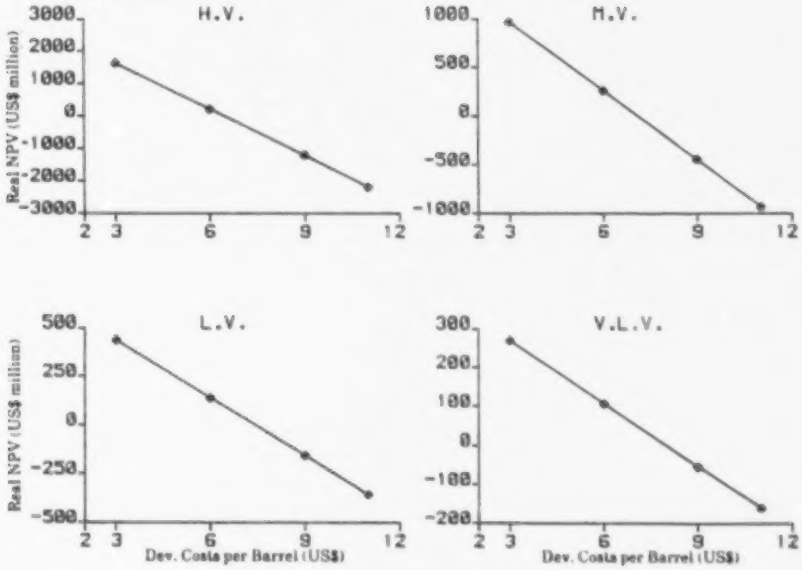


Figure 6.2 (continued)

B. Collapsed Real Oil Price - cont'd



The position in each of the countries is now examined in detail.

(1) Australia

Royalty/Production Levy System

The system incorporating royalty and production levy was discussed in Chapter 3. The initial case considered is one where the levy is deductible for royalty. Figure 6.3 shows the share of gross economic rents (as measured by the present value of the tax take as a percentage of the net present value, with a discount rate of 10 per cent) accruing to government; the base price is $27, reflecting the position as seen in 1985. Most likely field sizes are MV, while likely costs are in the LC to MC range. Under the range of oil price scenarios exhibited, it is seen that government's share of the rents shows little change under LC conditions, but when MC is reached the takes vary considerably with the oil price. The behaviour of the fiscal system is seen to be distinctly regressive in relation to oil prices: a higher share of the rents is taken by government when profitability (as defined by net present value) is reduced due to falling prices. It is also clear from Figure 6.3 that under all of the oil price scenarios, a higher share of the rents is taken by government when profitability falls due to higher exploitation costs. The system is distinctly inefficient.

These results emanate from the effects of the production-based elements of the fiscal system. The royalty and production levies both commence with first production. This, together with the non-deductibility of exploitation costs, means that they take an increasing share of the economic rents as profits diminish due to either rising costs or reduced oil prices. The system is so regressive in its impact that, while government takes under the falling real price leave the investor with a comfortable share of the rents under LC conditions, under MC conditions the government collects more than 100 per cent of the rents on most fields. The change is quite dramatic, particularly on the IVLV field, where the take under the falling real price increases from under 60 per cent at LC to approximately 110 per cent under MC conditions. The sliding-scale feature of the levy helps to keep the take on the smallest field below that from larger ones at LC, but the crude mechanism is unable to prevent the take from rising rapidly when profits fall due to reduced oil prices and higher costs.

At higher discount rates this fiscal system becomes more regressive. The total economic rents available of course decrease with higher discount rates. The working of the system at a 15 per cent rate is shown in Figure 6.4. Under LC conditions government takes are slightly higher than they are under the 10 per cent rate. Under MC conditions, however, takes are much higher on all fields. Further, under MC conditions the take under falling real prices increases much more than under rising real prices: the system is much more regressive in relation to oil price movements. The main cause of this outcome is, of course, the production-related aspect of the levy and royalty. Front-ended levies based on gross revenues will have a more adverse effect on post-tax returns the higher the discount rate employed.

Further insights into the operation of this fiscal system may be gleaned by considering its impact in money-of-the-day terms. It was found that in these terms the scheme is still regressive, though to a much milder degree than in present-value terms. The overall burden under all cost conditions is significantly lower. Nevertheless, the burden under MC conditions exceeds 80 per cent of resources generated on the HV and MV fields under the falling oil price.

While investors in the petroleum sector are likely to employ discount rates of at least 10 per cent, it is possible that social discount rates are lower. At a rate of 5 per cent, government take on the MV field under falling real oil prices is 72.9 per cent under LC conditions and 94.8 per cent under MC circumstances; on the LV field the figures are 68 per cent and 85.3 per cent respectively; and on the IVLV field, 59.1 per cent and 84 per cent respectively. The takes on the smaller fields are being kept down by the operation of the sliding-scale production levy. All the projects are thus acceptable to investors at this discount rate (5 per cent), in contrast to the position under the 10 per cent rate. At a 20 per cent discount rate the take under falling real prices under LC conditions is 82.8 per cent on the MV field, 73.6 per cent on the LV one, and 65.7 per cent on the IVLV one; under MC conditions government take exceeds the economic rents on all fields.

The above analysis indicates the behaviour of the fiscal system under oil price scenarios which could have been anticipated in 1985; the collapsed-price scenario would not have been anticipated. The working of the system with collapsed prices highlights its regressive nature. At 10 per cent discount rates government take under LC conditions is 80.6 per cent on the MV field, 73.7 per cent on the LV one, and 65.6 per cent on the IVLV one; under MC conditions, takes greatly exceed 100 per cent of rents on all fields. At a 15 per cent discount rate under LC conditions, the take is 87 per cent on the MV field, 77.7 per cent on the LV one, and 71.6 per cent on the IVLV one. At a 5 per cent discount rate, the takes are 76.6 per cent, 71.1 per cent, and 62.4 per cent on the three fields, respectively, under LC conditions; government takes still exceed 100 per cent on all fields under MC conditions. These findings not only indicate the regressive nature of the system but also show how disincentive effects can emerge as a consequence.

The system under collapsed oil prices is even distinctly regressive in money-of-the-day terms. This is shown in Figure 6.5, where it is seen that government takes are at comparatively high levels under LC conditions and become very onerous under MC conditions on all fields but particularly on the larger ones, where the impact of the production levy is greater.

In Queensland the state government does not allow the production levy as a deduction against royalty and, consequently, the total fiscal burden is higher under this jurisdiction. For example, with a 5 per cent discount rate total government take under the scenario of constant real oil prices (with $27 as the base value) on the MV field under LC conditions becomes 72.9 per cent, as opposed to 70.9 per cent with deductibility; on the LV field the figures are 67.9 per cent and 66.4 per cent respectively, and on the IVLV field 58 per cent and 57.6 per cent. With a 20 per cent discount rate the take becomes 81 per cent on the MV field (as opposed to 78.2 per cent with deductibility) and on the LV one 72.5 per cent (as opposed to 70.5 per cent).

Under the collapsed-price scenario, with a 10 per cent real discount rate, the take under LC conditions on the MV field becomes 83.3 per cent compared with 80.6 per cent for deductibility; on the LV field it becomes 75.8 per cent compared with 73.7 per cent. At a 15 per cent discount rate the take becomes 90.2 per cent on the MV field compared with 87 per cent, and 80.1 per cent compared with 77.7 per cent on the LV one. These changes represent significant differences in post-tax net present values. For example, on the MV field at 20 per cent discount rate, the net present value becomes $196.1 million compared with $228.1 million.

In Australia the government take is divided between the Commonwealth and State governments, with the State Government obtaining the royalty. Figures 6.6, 6.7, and 6.8 show examples of the division of the proceeds between the tiers of government. Figure 6.6 illustrates the respective shares of the Queensland and Commonwealth governments in the economic rents under the scenario of a constant real oil price with a base value of $27. The share of the Queensland Government is seen to increase as project profitability falls due to increased costs. This is primarily because royalties are a function of gross revenues rather than profits. It is also noteworthy from Figure 6.6 that the share of the Commonwealth Government also increases with rising costs. The production levy plays the dominant role in producing this result. This also explains why the Commonwealth Government's share increases to a greater extent on the larger fields.

Figures 6.7 and 6.8 show the shares accruing to the two tiers of government in nominal terms under the collapsed-price scenario. The differences highlight the effects of the deductibility or non-deductibility of the production levy for royalty. With the non-deductible production levy the state's share on all fields is increased, with the gain being greater on the larger fields simply because the levy is much greater for them. It can also be seen that the gain to the state from non-deductibility is greater under less profitable situations on all fields – the relative burden of the production levy increases as profits fall, but non-deductibility for the royalty helps to boost the yield of the latter. At the same time, the yield of the income tax goes down markedly as costs increase, due to a combination of lower profitability and the deductibility of both production levy and royalties.

The working of the fiscal system as it relates to exploration decisions is now examined. The methodology again follows that outlined in Chapter 5. The pre-tax EMVs shown are not necessarily equal to the post-tax EMVs "grossed up" by the tax take. The tax take refers to the expected payments on field situations which by themselves are acceptable on a post-tax basis; the pre-tax EMVs refer to field situations which are viable on a pre-tax basis. This procedure is in line with the actual exploration decision-making process as discussed in Chapter 2. The alternative procedure – simply calculating post-tax EMVs on the basis of field situations which are viable on a pre-tax basis – gives a distorted view of exploration decision-making and frequently produces very unrealistic results. Under the methodology adopted here, any difference between the pre-tax EMVs and the "grossed up" values of the post-tax EMVs measures the loss of social value from the non-development of field situations which are viable on a pre-tax basis but not viable post-tax.

Cases of several sizes of exploration programs and various success rates were considered. The results were also examined at different discount rates. The base case was one where the size of the exploration program was $20 million in real terms.

Table 6.1 summarizes the pre-tax results for an ongoing investor under the constant real oil-price scenario with base value $27 per barrel.

With a $20 million exploration program, pre-tax EMVs are always positive except at a discount rate of 15 per cent where the probability of discovery is only 1 in 20. Post-tax EMVs generally remain positive except at high discount rates and low overall success rates. The tax system is seen to inhibit exploration in relatively few situations. The anticipated tax take increases as the investor's expected pre-tax returns fall, however. As was found before, when the deterministic analysis was conducted, the fiscal system is regressive and can thus produce disincentives.

Clearly, the larger the size of the exploration program the greater the likelihood of negative EMVs being produced and the greater the chances of the tax system producing disincentives. Thus, with a $60 million program under the situation with an overall 1 in 10 chance of success, the pre-tax EMV is negative only at a discount rate of 15 per cent, but on a post-tax basis it is negative at rates of 5 per cent and 10 per cent as well as 15 per cent; in the situation with a 1 in 5 chance of success, the EMV is positive on a pre-tax basis at 15 per cent discount rate but negative post-tax. Again the tax take is regressive, increasing as the EMV falls in size. There is thus clear evidence that the fiscal system inhibits exploration on the assumption of fairly low success rates, with high discount rates, or when expensive exploration programs are required.

Table 6.1
Australia (Royalty/Production Levy System)
Expected Monetary Values and Government Takes
facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	325.2	89.9	71.5
5	197.8	49.7	74.2
10	119.1	24.4	79.2
15	68.4	7.8	88.7
Overall Discovery Rate: 1 in 10			
0	152.6	39.9	73.0
5	88.4	19.5	77.3
10	48.5	6.6	86.2
15	22.6	-2.0	108.8
Overall Discovery Rate: 1 in 20			
0	66.3	14.8	76.7
5	33.7	4.4	86.5
10	13.2	-2.4	118.4
15	-0.3	-6.9	-

Note: Dash (-) indicates results are not economically meaningful.

Under the collapsed-oil-price scenario the position with a $20 million program is given in Table 6.2. As could be expected, the EMVs are much lower compared with the situation of a constant real price, and the fiscal system turns several more situations from positive to negative; for example, with a 1 in 5 chance of success the post-tax EMV turns negative at a 15 per cent discount rate. The regressive nature of the fiscal system becomes more marked under this oil price scenario.

Table 6.2
Australia (Royalty/Production Levy System)
Expected Monetary Values and Government Takes
facing Explorationist, $20 Million Program
Collapsed Real Oil Price

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	155.3	29.3	76.7
5	85.7	12.0	83.0
10	42.4	1.0	97.2
15	14.5	-6.2	142.6
Overall Discovery Rate: 1 in 10			
0	67.7	9.6	82.0
5	32.3	0.6	97.4
10	10.2	-5.1	170.6
15	-4.3	-9.0	-
Overall Discovery Rate: 1 in 20			
0	23.8	-0.3	102.0
5	5.7	-5.0	359.1
10	-5.9	-8.2	-
15	-13.7	-10.4	-

Figure 6.3
Australia (Royalty/Production Levy System)
Government Share of Economic Rents, 10% Real Discount Rate
1986 Price Perspectives

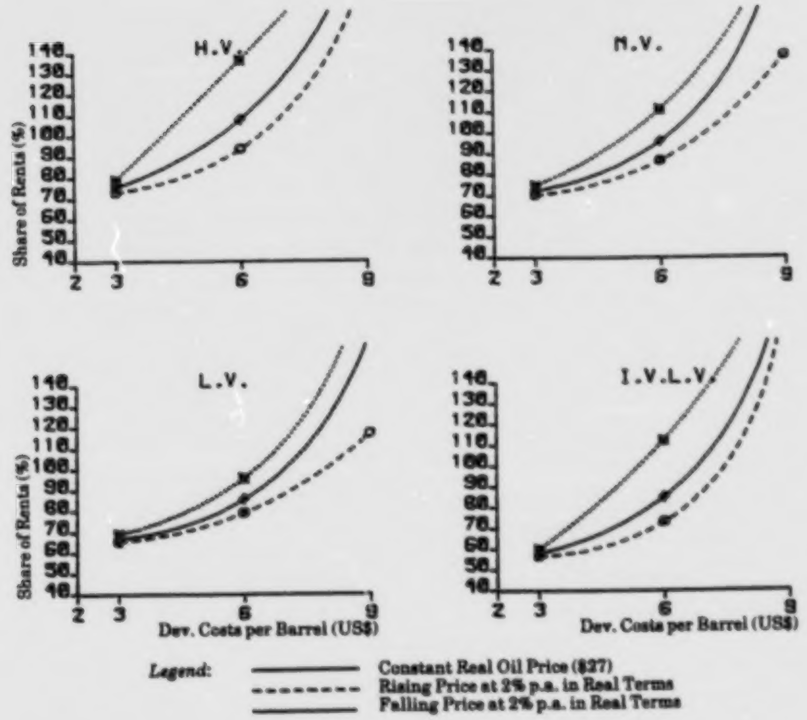


Figure 6.4
Australia (Royalty/Production Levy System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

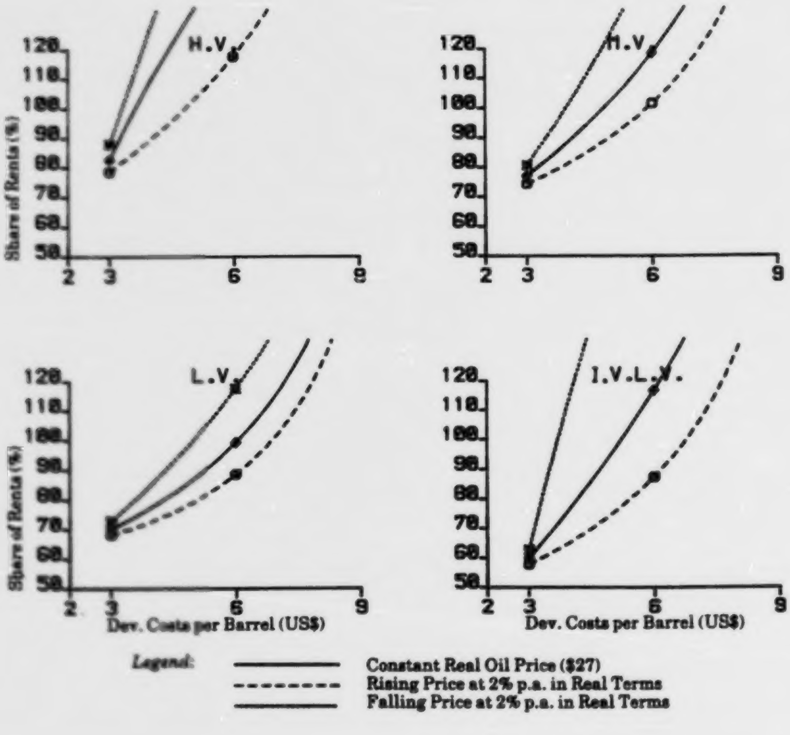


Figure 6.5
Australia (Royalty/Production Levy System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price

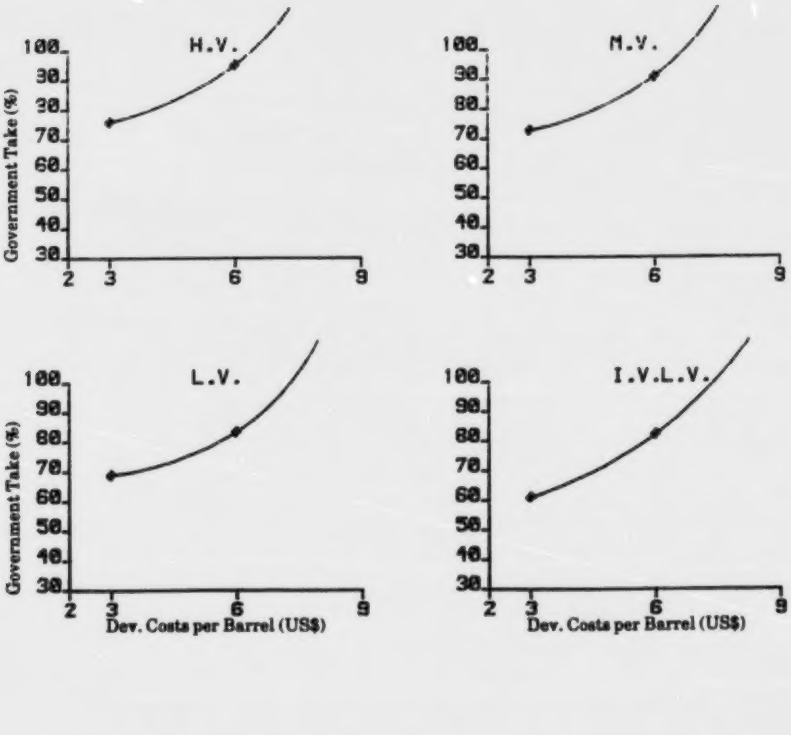


Figure 6.6
Australia (Royalty/Production Levy System)
Distribution of Economic Rents, 10% Real Discount Rate
Constant Real Oil Price ($27)

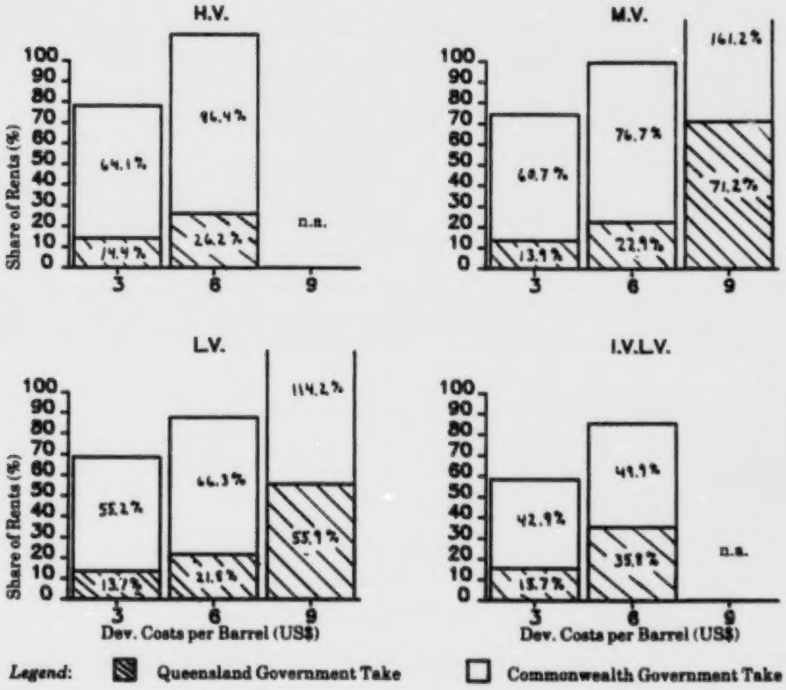


Figure 6.7
Australia (Royalty/Production Levy System)
Distribution of Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price

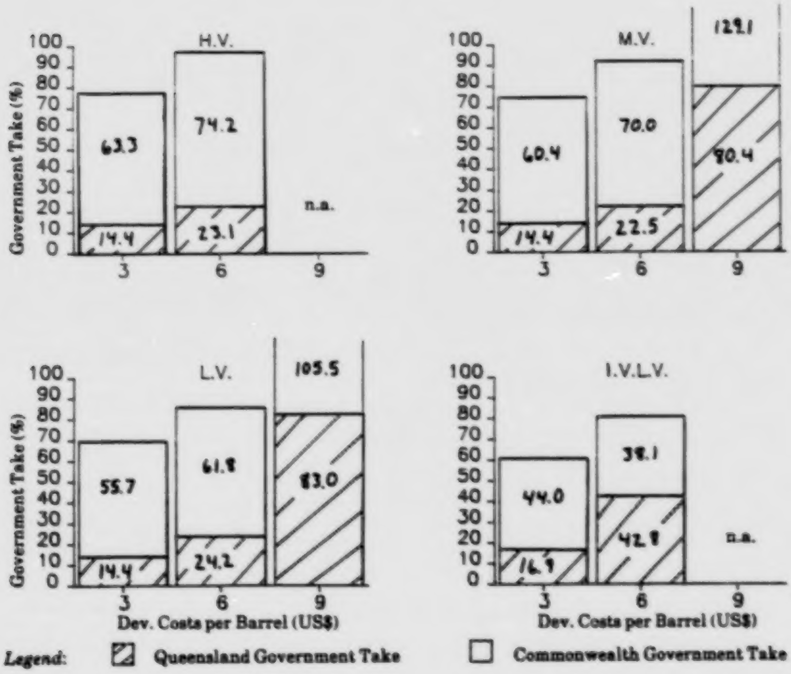
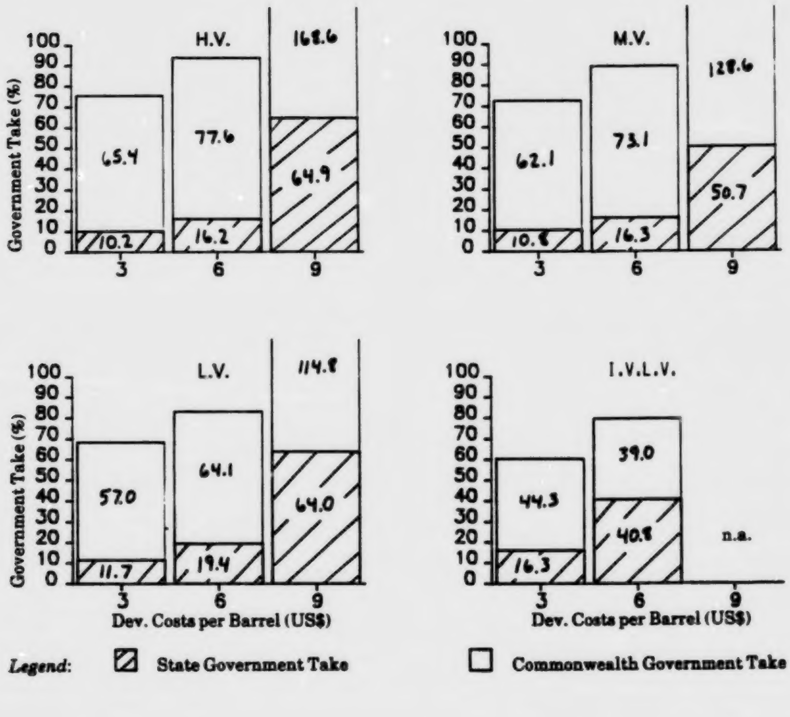


Figure 6.8
Australia (Royalty/Production Levy System)
Distribution of Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



Resource Rent Tax System

The government share of economic rents under the system incorporating the resource rent tax is shown in Figures 6.9 and 6.10. Figure 6.9 is based on a 10 per cent discount rate, and Figure 6.10 on 15 per cent; the oil price scenario for both are those that could have been expected in 1985. The performance of this system is strikingly different from that of the more conventional scheme already discussed. From Figure 6.9 it is seen that in the $3- to $6-per-barrel range of development costs, as costs increase the tax take in discounted terms is usually either constant or falling. This is an economically efficient result. At higher cost levels the take increases in the majority of situations depicted; in general this is inefficient. The share of rents collected by the state is seen never to exceed 70 per cent. This reflects the very high threshold rate used.

The frequent fall in the tax take in the $3 to $6 cost range is primarily due to the operation of the Resource Rent Tax (RRT), backed up by the favourable effect of the investor's being able to offset some of the costs of developing the fields against his other income for corporate income-tax purposes; the automatic reduction in the burden of the RRT as discounted profitability falls, plus the front-end alleviation of income tax, causes the total government take to fall. From Figure 6.9 it is seen that the system tends to be most progressive in relation to cost changes under the rising real oil price. Under this scenario the RRT constitutes a bigger share of the total tax take than under less profitable circumstances, and the automatic decrease in the burden of this tax as costs increase consequently exerts a more powerful influence on the whole take.

Under the other price scenarios the income tax exerts an increasing influence on the total take as costs increase. The position under the constant real oil price is shown in Figure 6.11. The increasing dominance of the income tax is responsible for the regressive nature of the system at higher cost levels. As profitability in discounted terms becomes very low, the burden of the conventional income tax becomes more onerous. This is illustrated in Figure 6.9 where the burden under HC conditions is seen to be greater under the scenario of falling oil price.

Figure 6.9 also shows that the system is frequently progressive with respect to oil prices in the $3 to $6 cost range. This situation is reversed when costs become higher. When the RRT exerts a major influence on the total tax take the system is progressive in relation to price changes, but at low profitability the dominance of the income tax reverses this situation. The very high threshold rate for the RRT prevents the government take from increasing further under the rising oil price.

The rather different behaviour of this fiscal system under a 15 per cent discount rate (see Figure 6.10) is explained by the factors discussed above. At the 15 per cent rate the projects generate lower economic rents, and there is a greater chance that a fiscal system will tax returns below the discount rate. The danger is greater with a conventional income tax than with the RRT, because the depreciation provisions may not reflect the higher cost of capital. This factor explains why the system becomes more regressive at the higher discount rate. At a 20 per cent discount rate (results not illustrated) the system still produces government takes of less than 100 per cent of the rents under constant real prices on the MV and LV fields, though on the IVLV field the take significantly exceeds 100 per cent.

Under the scenario of collapsed oil prices, at a 10 per cent discount rate, government takes on the MV field are 65.3 per cent at LC and 71.1 per cent at MC conditions; on the LV field the corresponding figures are 65.9 per cent and 64.3 per cent respectively; on the IVLV field the take is 64.9 per cent at LC conditions. At a discount rate of 15 per cent the take is under 70 per cent at LC conditions on all field sizes; under MC conditions, however, the takes exceed 100 per cent of the rents. The behaviour of the system in money-of-the-day terms under the collapsed oil price is shown in Figure 6.12. It is seen that the scheme remains progressive in most cases.

The conclusion is thus that this RRT system performs better than the royalty/production levy scheme over the wide range of oil price and field cost conditions examined. Distortions are primarily due to the structure of the income tax. The extremely high threshold rate for the RRT limits the share of rents accruing to government under highly profitable conditions to such an extent that the details of the scheme can still be questioned on grounds of accuracy of targeting.

The post-tax position regarding the explorationist operating under the RRT system is shown in Table 6.3. Under a constant real price of $27, it is seen that the RRT-based system produces considerably less inhibitions on exploration compared with the system incorporating royalty and production levy. The fiscal system is seen to be only moderately regressive in its impact as profitability decreases due to higher technical costs, costs of capital, or lower overall success rates. Under the collapsed oil price more situations emerge in which the fiscal system does produce disincentives to explore. The scheme becomes more regressive, to a severe level, at situations of low profitability. On the whole, however, the system performs credibly well, in terms of economic efficiency, over the wide range of circumstances examined.

Table 6.3
Australia (Resource Rent Tax System)
Post-Tax Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program
Constant and Collapsed Real Oil Prices

Real Discount Rate (%)	Constant Real Oil Price ($27)		Collapsed Oil Price	
	Post-Tax EMV (US$ million, 1986)	Gov. Take (%)	Post-Tax EMV (US$ million, 1986)	Gov. Take (%)
Overall Discovery Rate: 1 in 5				
0	111.3	65.6	53.2	64.7
5	66.8	66.2	27.4	67.4
10	37.9	68.3	12.1	72.5
15	18.5	73.4	0.3	97.9
Overall Discovery Rate: 1 in 10				
0	50.5	66.7	21.5	67.1
5	28.0	68.3	7.8	74.8
10	13.3	72.7	1.0	91.7
15	3.3	85.6	-5.7	-
Overall Discovery Rate: 1 in 20				
0	20.2	69.4	5.6	75.1
5	8.7	74.3	-2.0	144.8
10	1.0	92.3	-4.6	-
15	-4.2	-	-8.8	-

The results also indicate the risk-sharing attributes of the conventional income tax for an ongoing investor. Where the government shares exploration costs through forfeiting tax revenues from existing projects, this can improve a pre-tax negative EMV; the post-tax EMV, while remaining negative, can actually be reduced to a smaller negative value. The regulations for the RRT, by not allowing a deduction for unsuccessful exploration, are economically inefficient. The high threshold rate does not constitute an appropriate compensation.

Figure 6.9
Australia (Resource Rent Tax System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

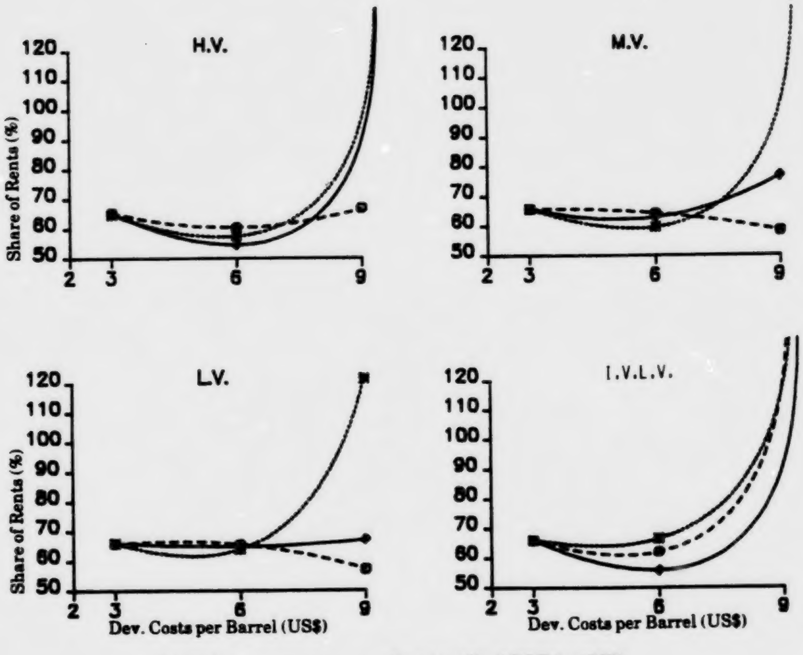


Figure 6.10
Australia (Resource Rent Tax System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

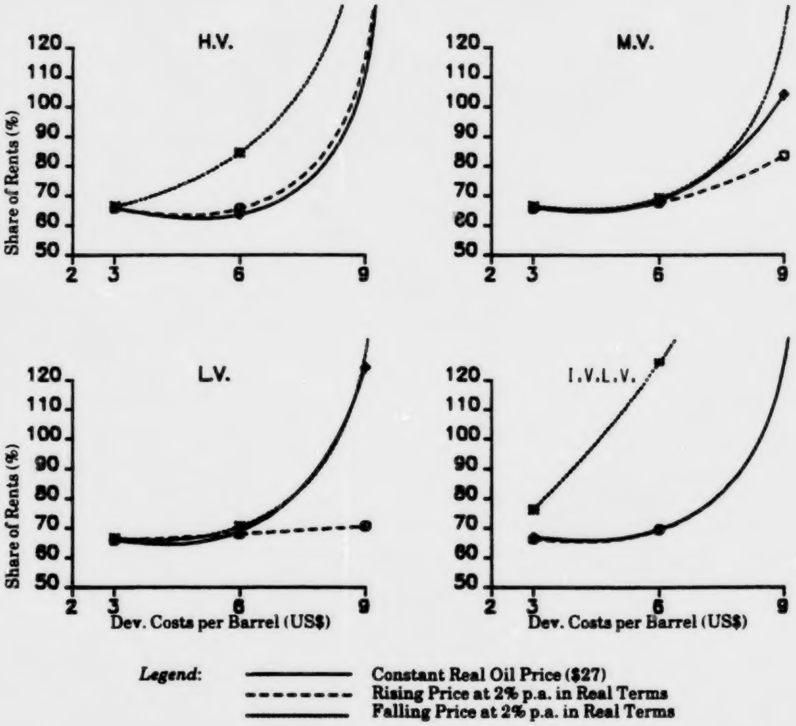


Figure 6.11
Australia (Resource Rent Tax System)
Distribution of Economic Rents, 10% Real Discount Rate
Constant Real Oil Price ($27)

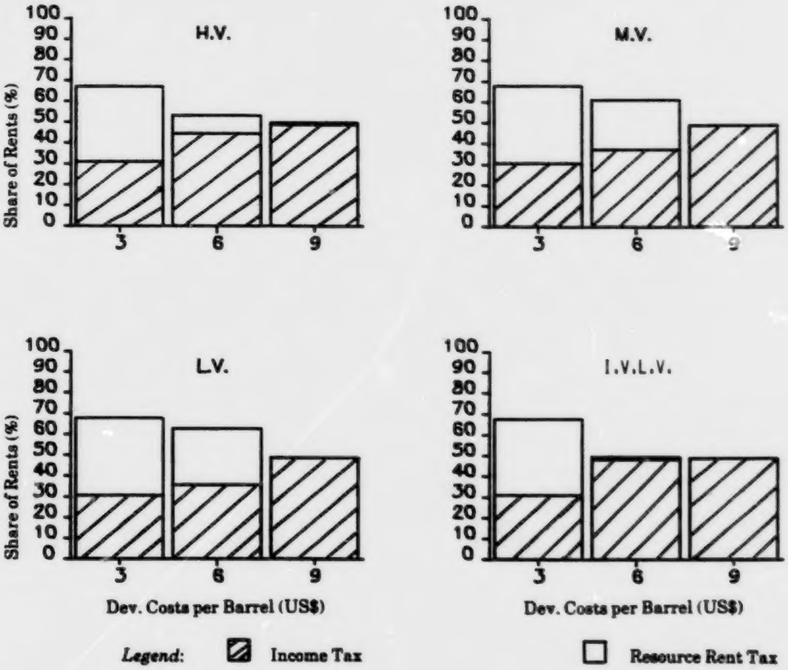
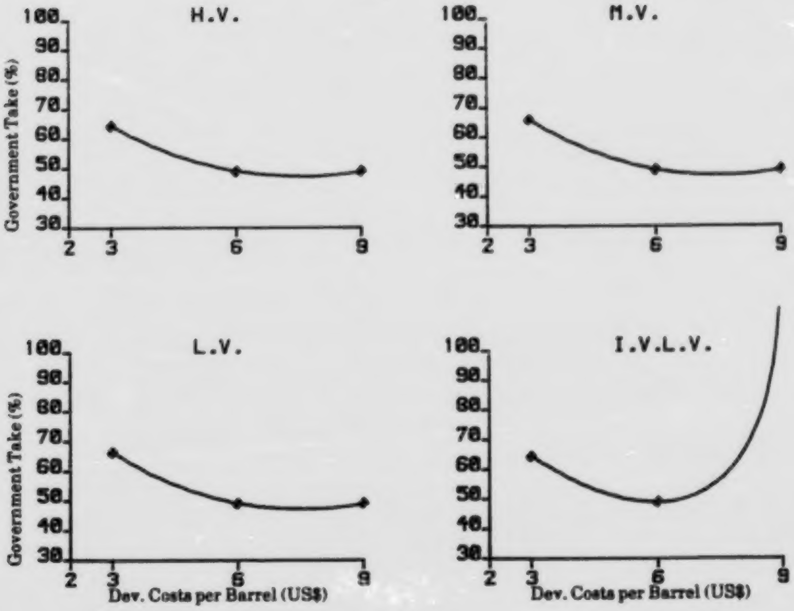


Figure 6.12
Australia (Resource Rent Tax System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(2) United Kingdom

The state's shares of economic rents under price scenarios expected in 1985 are shown in Figure 6.13 for a 10 per cent discount rate. The fiscal system is seen to behave such that under rising real prices the take is progressive across most of the fields and proportional on the VLV one. The absence of royalties on new fields combines with the effects of some features of both the PRT and corporation tax systems to produce this result. A combination of the "uplift" and safeguard provisions for PRT ensure that this tax is progressive in money-of-the-day terms and sometimes in present-value terms. For an ongoing investor the ability to offset rapidly at least some of the costs of a new field development against other income produces a progressive income tax when profitability is reasonably high. The net result is a system which is progressive in relation to changes in profits caused by cost increases.

The same features ensure that at relatively low cost levels the fiscal system is progressive in relation to changes in profits caused by oil price movements. Unfortunately, in the range of costs now most likely to be found in the U.K. North Sea (namely, MC to HC), the fiscal system becomes regressive in relation to oil price changes; by the time HC is reached, the take is highest under falling real oil prices and lowest with rising real prices.

At a discount rate of 15 per cent the picture, as shown in Figure 6.14, is different. The fiscal system is highly regressive with respect to both oil prices and cost changes especially in the MC to HC range, which typifies present conditions. The allowances for PRT and corporation tax are insufficiently strong to prevent the government take from rising strongly as profitability falls. The reliefs for drilling costs are on a 100 per cent first-year basis and for plant and machinery costs at 25 per cent on a declining-balance basis; together they are too slow to prevent the take from increasing rapidly in a situation of falling real prices and rising costs.

From the trends discussed above it is no surprise to find that the system becomes more regressive in discounted terms under collapsed oil prices. Figure 6.15 shows the effects with a 10 per cent discount rate. Perhaps the most remarkable finding is that under MC conditions the system still produces takes well below 100 per cent of the economic rents. Even at a 15 per cent discount rate the takes under MC conditions remain tolerable on the LV field (84.7 per cent) and the VLV one (47.9 per cent).

The U.K. system is an adaptation of a conventional fiscal system. For an ongoing investor it is seen that, despite its many complexities, it produces an effect which encourages field developments over a wide range of oil price and cost conditions. The system does not always collect economic rents in a very accurate fashion, but compared with many others in this study it is reasonably flexible to changes in the operating environment. The U.K. system has imperfections emanating from the basic problem that the chosen instrument is only indirectly related to its target: the appropriate target is the net present value at the investor's discount rate, and the U.K. fiscal system relates to this at best in a cumbersome manner, and at worst inaccurately.

Table 6.4 shows the position of the explorationist in the U.K. sector contemplating a program of $20 million on an ongoing basis for a constant real oil price of $27. The results show that, with a 1 in 5 chance of discovery, pre-tax EMVs are positive except at a discount rate of 15 per cent. With a chance of 1 in 10 the result is positive only at discount rates below 10 per cent, while with a chance of only 1 in 20 there is no positive EMV at any positive discount rate. The post-tax position generally reflects the favourable fiscal treatment given to exploration expenditure by an ongoing investor in the United Kingdom. Effective tax takes are low because the expected fields are small in size and pay little PRT. Exploration costs are relieved at 83.75 per cent on a 100 per cent first-year basis; in the calculations, this front-end relief to the ongoing investor is regarded as a negative tax. The ongoing investor also obtains the benefit of front-end relief for corporation tax on his expenditure on new field development. When the discounting process is undertaken, the effective tax take can sometimes be negative. This is especially the case when the subsequent tax payments on a discovered field are very small. The fiscal system is certainly helpful to ongoing investors.

In the U.K. sector, exploration programs of amounts larger than $20 million are not uncommon. With a program of $60 million it was found that pre-tax EMVs were negative at all discount rates when the chance of success was 1 in 10 or worse; with a 1 in 5 chance of discovery the EMV was positive at discount rates below 10 per cent. Effective tax rates (as defined above) were generally low in discounted terms and on some occasions negative. Thus, exploration incentives were hardly impaired by the tax system when viewed in discounted terms.

Under the collapsed oil price with an exploration program of $20 million, pre-tax EMVs are nearly always negative on the overall discovery rates of 1 in 5, 1 in 10, or 1 in 20, but the size of the negative EMV increases sharply as prospectivity declines. Post-tax EMVs are thus also generally negative as well. However, the fiscal system is, for the most part, not the main deterring factor; exploration incentives are low primarily because of the low level of oil prices in relation to likely exploitation costs. To an ongoing investor, effective tax rates are generally low and in discounted terms the tax system—with its loss-sharing provisions resulting from the front-end loading of reliefs for expenditure – can hardly be said to be a deterrent.

Table 6.4
United Kingdom Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	122.4	77.3	29.1
5	51.4	36.1	23.6
10	10.6	12.1	-ve
15	-13.3	-2.2	-ve
Overall Discovery Rate: 1 in 10			
0	51.2	36.6	17.8
5	15.2	15.5	-ve
10	-5.7	3.0	-ve
15	-18.2	-4.5	-ve
Overall Discovery Rate: 1 in 20			
0	15.6	16.3	-ve
5	-2.9	5.2	-ve
10	-13.9	-1.5	-ve
15	-20.7	-5.6	-ve

Note: *-ve* indicates the tax take is negative.

In sum, from the viewpoint of economic efficiency, the U.K. fiscal system performs reasonably well when applied to new investments. The system is profit-related and does take account of differences in cost conditions likely to be encountered in the North Sea. Differences between pre-tax and post-tax rates of return are modest in comparison with many other countries discussed in this study. Reliefs for exploration are fairly generous, and incentives for new exploration are comparatively strong. The U.K. system is noteworthy for the extent to which exploration risks are shared by the government. Development costs are also shared to a significant extent. The fiscal system is only indirectly related to the target of economic rents, however, and this inevitably produces some lack of accuracy. The PRT is very complex, and therefore costly, and the need to make some discretionary modifications as the operating environment changes is a further drawback.

Figure 6.13
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

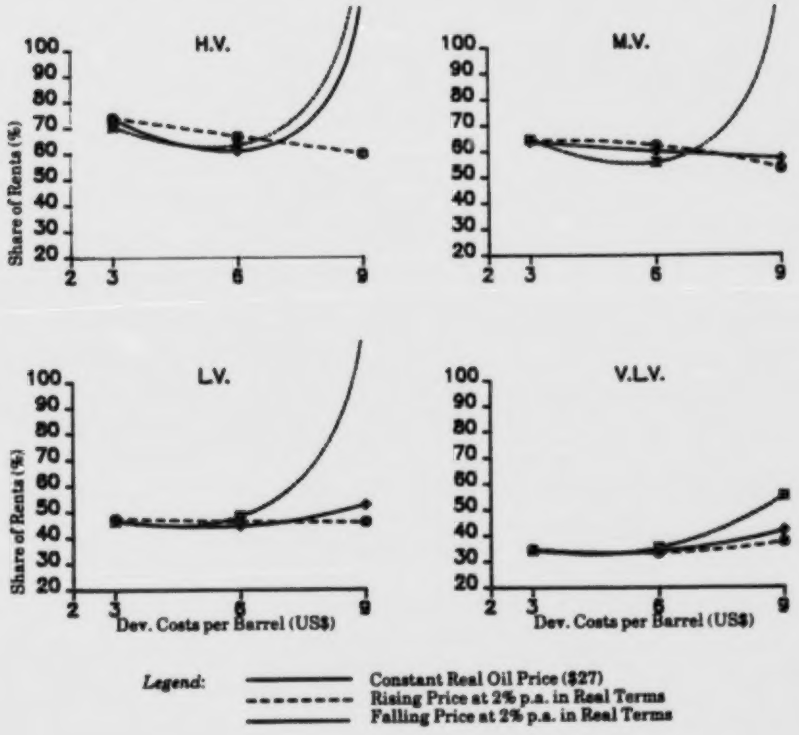


Figure 6.14
United Kingdom
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

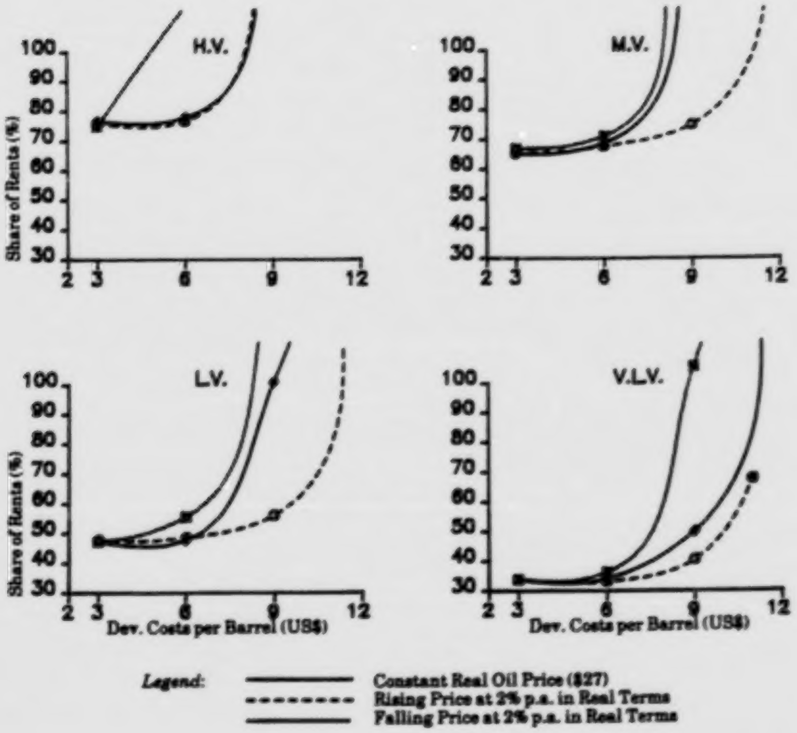
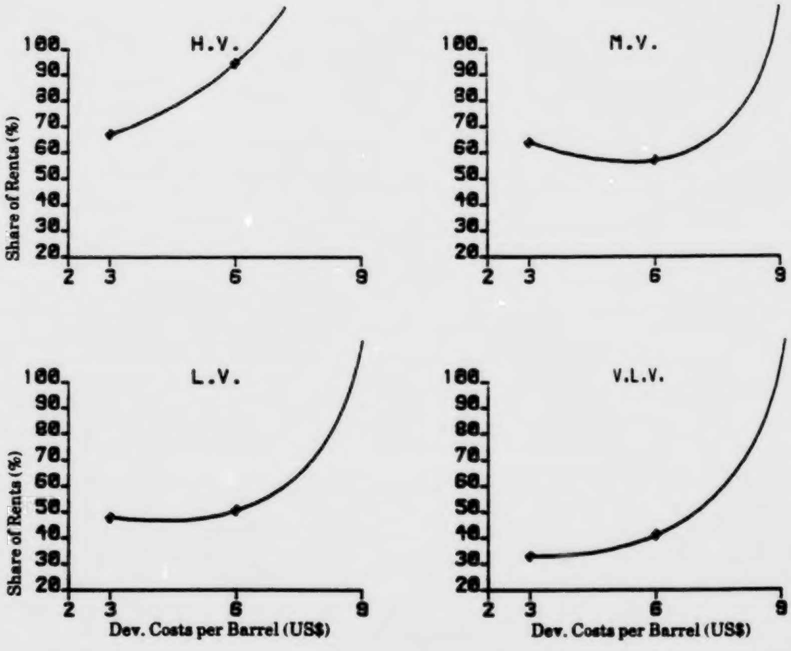


Figure 6.15
United Kingdom
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price



(3) Norway

The share of economic rents accruing to the state from petroleum exploitation in Norway is shown in Figures 6.16 and 6.17. Both figures illustrate the working of the Norwegian system under the oil price perspectives of 1985, at a discount rate of 10 per cent, but Figure 6.16 includes the government's take from taxes only, while Figure 6.17 includes state participation.

Figure 6.16 shows that the tax system is regressive and can collect more than 100 per cent of the rents. Projects will generally have development costs in the $3- to $6-per-barrel range, though some have considerably higher cost levels. It is seen that post-tax returns exceeding 10 per cent are sometimes not available when development costs attain $6 per barrel. On all fields the takes increase with lower oil prices. Similarly, the takes rise as project profitability falls due to cost increases. Several features of the fiscal system bring about this result – depreciation provisions for development costs for both income tax and Special Tax are on a six-year straight-line basis commencing with the year in which expenditure is incurred; this makes the system regressive in present-value terms, while the high marginal and average rates produce the high overall takes.

The position with government participation added (Figure 6.17) shows that with development costs of $3 per barrel participation significantly increases the state's share of economic rents. However, at development costs of $6 and more, the state's total share actually goes down compared with the tax-only situation, because the state company is then sharing in the project's post-tax present-value losses; in these situations the state would be better not to participate at all.

The fiscal system becomes both more severe and regressive the higher the discount rate employed. In Figure 6.18 the state's take (including participation) is shown at a 15 per cent discount rate. The difference between the take under falling real prices and that under rising prices becomes distinctly more marked. Under falling real prices the take is seen to become dramatically regressive and severe, on the large fields in particular.

As was discussed in Chapter 3, the institutional framework in Norway – with the dominant role of Statoil in investment decision making – suggests that the effective discount rates employed in project appraisal could be lower than in other countries, where private-sector firms are less inhibited. It is thus useful to consider the effects of the Norwegian fiscal system at lower discount rates. At a 5 per cent rate, on the assumption of constant real oil prices at $27 per barrel, the tax take on the VHV field is 73.9 per cent at LC and 79.0 per cent at MC conditions; on the HV field it is 73.6 per cent and 77.2 per cent respectively; on the MV field, 81.1 per cent and 76.7 per cent respectively; on the LV field the take is 73.4 per cent at LC, 76.2 per cent at MC, and 84.7 per cent at HC conditions. The conclusion that the size of discount rate employed makes a considerable difference to government takes in the Norwegian system is thus reinforced. If effective discount rates in Norway are lower than in other countries, there could be a significant effect on incentives.

Under the collapsed-price scenario the system is highly regressive in present-value terms. With development costs of $3 per barrel, the tax takes are around 80 per cent on all sizes of fields; as costs increase, the take rises sharply. The position with a discount rate of 10 per cent (participation included) is shown in Figure 6.19. At development costs of $6 per barrel the takes clearly exceed the rents. With a 5 per cent discount rate, tax takes are under 90 per cent under LC conditions on all fields; under MC conditions the takes are 85.4 per cent on the MV field, 83.8 per cent on the LV, and 83.3 per cent on the VLV one.

The position facing an explorationist in Norway contemplating a program costing $20 million, under the 1985 oil price perspective, is shown in Table 6.5. The pre-tax and participation EMVs are positive at all discount rates apart from the 15 per cent one. The expectation of relatively large fields in the Norwegian sector is a main factor in the determination of the positive outcomes. After tax and state participation, expected returns are usually reduced markedly by the fiscal system – EMVs to investors are now negative at positive real discount rates when chances of success are 1 in 10 or 1 in 20. The government shares to a large extent in the exploration risks through high and rapid write-off for exploration costs. This provides some compensation for the high tax takes on discovered fields. At high discount rates and very unfavourable prospectivity, the front-end relief for exploration can be so influential that the overall expected tax take becomes negative. Prospectivity in Norway is comparatively high. Many investors anticipate a discovery chance of at least 1 in 5. This helps to explain the continuing interest in this country.

For an exploration program of $60 million, pre-tax EMVs are negative under all levels of prospectivity at a discount rate of 15 per cent. With success rates of 1 in 10 or less, pre-tax EMVs are negative with discount rates of 10 per cent, while post-tax EMVs become negative at real discount rates of 5 per cent. With a 1 in 5 success rate the post-tax EMVs are positive at a 5 per cent discount rate. The expected tax takes would often exceed 100 per cent of the expected rents.

The explorationist executing a program costing $20 million under the scenario of collapsed oil prices faces pre-tax EMVs that are negative at discount rates of 10 per cent and above when chances of success are 1 in 5, or worse. On a post-tax basis, EMVs are negative at discount rates of 5 per cent. The government again shares to a marked extent in the exploration losses by giving immediate relief for these costs to the ongoing investor for both income tax and Special Tax.

Table 6.5

Norway (State Participation Included)

Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program

Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)	
	Pre-Tax	Post-Tax and Participation	Tax	Total
Overall Discovery Rate: 1 in 5				
0	572.8	42.6	71.2	90.4
5	245.6	12.6	79.4	93.9
10	79.8	-2.3	100.8	103.2
15	-6.1	-9.7	261.2	174.3
Overall Discovery Rate: 1 in 10				
0	276.4	19.9	70.5	90.6
5	112.3	4.8	78.6	94.8
10	28.9	-2.7	106.7	110.0
15	-14.6	-6.5	-ve	-ve
Overall Discovery Rate: 1 in 20				
0	128.2	8.5	68.9	91.1
5	45.6	0.9	76.5	97.5
10	3.4	-2.9	-	-
15	-18.9	-4.9	-ve	-ve

In sum, the Norwegian fiscal system is not sufficiently flexible to cater for the range of operating circumstances likely to be found without economic inefficiencies emerging. The reformed system of state participation, while more profit-related than the previous one, is not sufficiently sensitive to changes in profitability, whether from oil price movements or cost changes. Given that it has a high marginal rate, the system is not well enough related to economic rents. When moderate rates of depreciation and high rates of tax are combined in a tax structure, it is extremely important to ensure that the system is accurately targeted if it is to perform in an efficient manner.

Figure 6.16
Norway (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

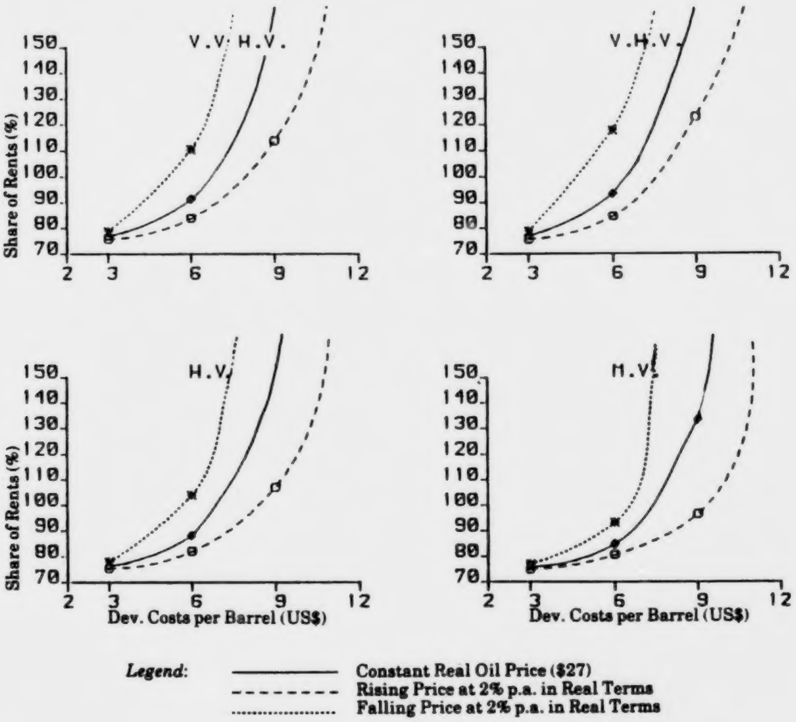


Figure 6.17
Norway (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

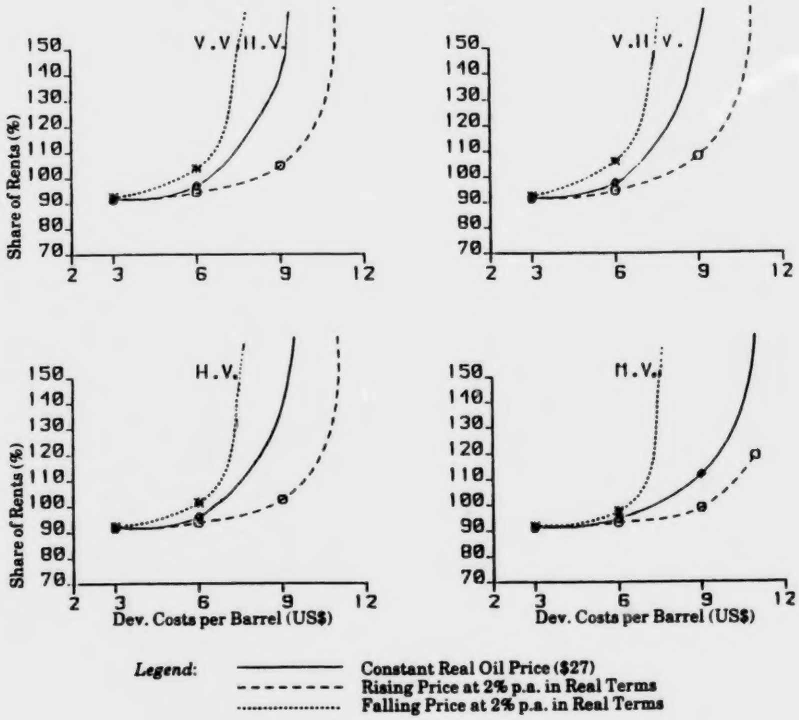


Figure 6.18
Norway (State Participation Included)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

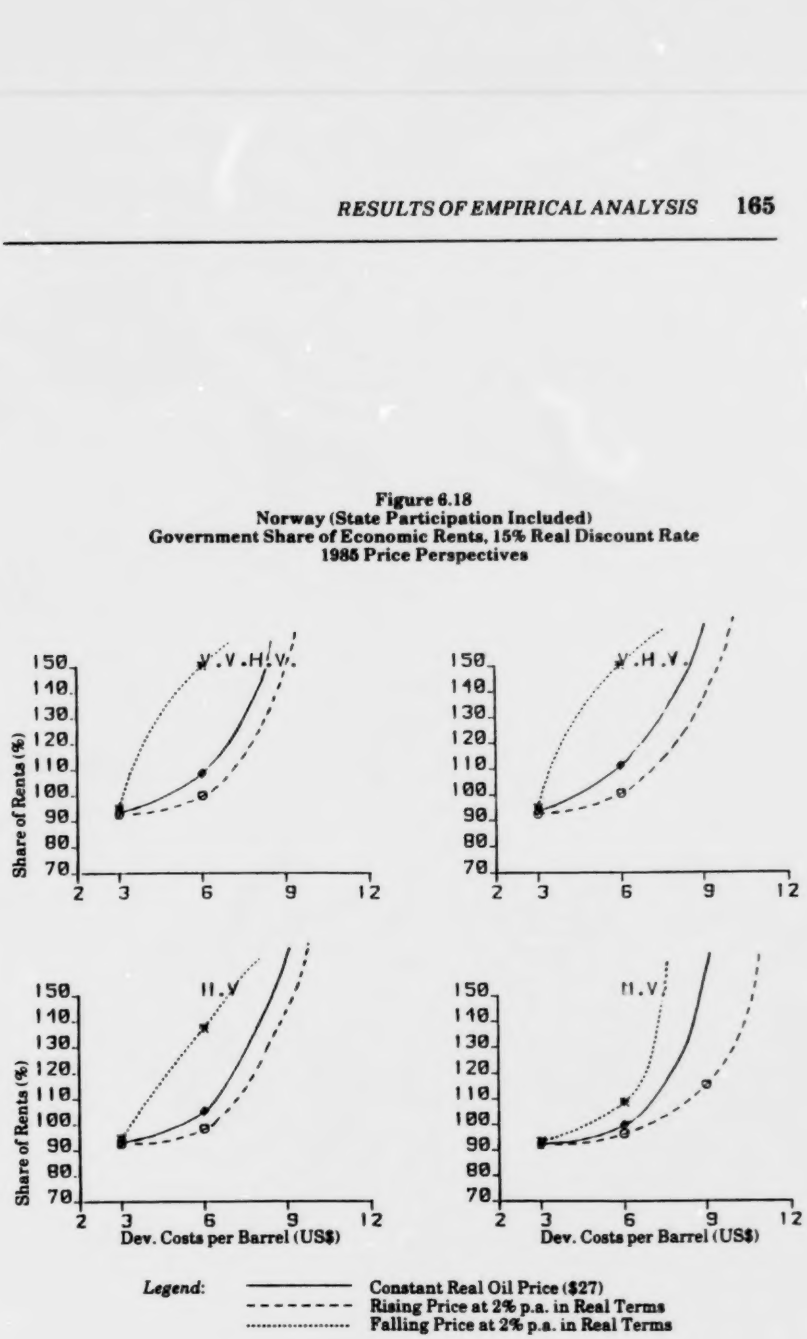
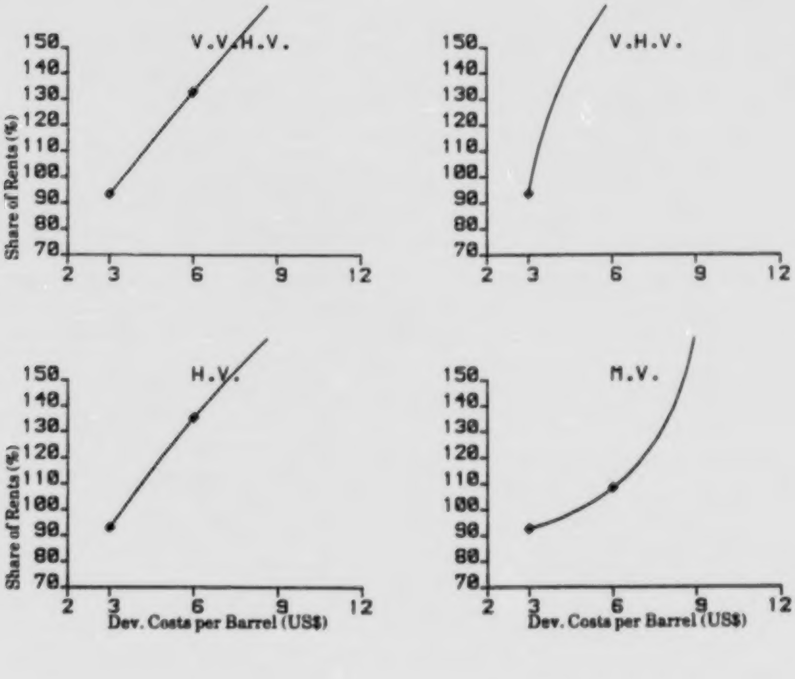


Figure 6.19
Norway (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price



(4) Indonesia

The shares of the Indonesia government in economic rents from petroleum exploitation in different fields are shown in Figures 6.20 and 6.21 for a 10 per cent discount rate under the 1985 oil price perspectives. This fiscal system included the domestic-market obligation at very low prices. Figure 6.20 shows the government's share of the economic rents calculated at world prices; in Figure 6.21 the rents are measured at the price actually received by investors (DMP). The latter chart indicates the possible disincentive effects of the Indonesian fiscal system on investors. The fiscal system is seen to be distinctly regressive in present-value terms in relation to changes in both oil prices and costs. It should be remembered that exploitation costs in Indonesia are relatively low compared with other parts of the world; the LC situation would be typical in current new offshore ventures, and costs below that level are possible. Nevertheless, the full range of costs is shown here in order to facilitate inter-country comparisons and to obtain a better picture of the operation of the system.

At the levels of oil prices expected in 1985, in money-of-the-day terms the Indonesian fiscal system, when measured at the DMP, is generally proportional with respect to both oil price and cost changes and generally progressive when measured at world prices. The scheme becomes regressive in present-value terms due to the fairly "slow" depreciation provisions both for cost-recovery purposes under the production-sharing agreement and for income tax. Investors in Indonesia have to form a new company for each contract area and income tax is levied separately on each company with no group relief being allowed. The effect is to make the investor's position essentially similar to that on a project basis and delay the receipt of expenditure reliefs. The effective rate of tax in present-value terms is thus increased.

The government's share of economic rents expressed in terms of world prices (Figure 6.20) is seen to be below that calculated at the investor's prices (Figure 6.21). The difference, namely, the share of rents accruing to local purchasers of crude oil, was found to vary—at a 10 per cent discount rate under LC conditions, from 2.5 to 3.4 per cent on the most likely field sizes, up to 4.7 per cent on the HV field. As exploitation costs rose the share of rents accruing to oil purchasers rose, varying from 4 to 10 per cent at HC conditions according to field size. In money-of-the-day terms the consumers' share of resources generated was rather higher, ranging from 3.7 to 6.5 per cent across the various fields at LC conditions and from 4.6 to 9.3 per cent under MC conditions. The share is less in present-value terms because there is no domestic-market obligation at a "low" price over the first five years of field production.

The government share of economic rents increases quite rapidly when a higher discount rate is employed. The position with a 15 per cent rate is shown in Figure 6.22. The increase in the government's share generally follows from the combination of a high nominal rate of tax with a moderate pace of relief for exploitation costs. The regressive nature of the system results in some projects being unacceptable to investors, even at LC conditions, under falling real prices. With a 5 per cent discount rate, under falling real prices across the range of fields at LC conditions, the government takes 91 to 93 per cent of the economic rents at the prices received by investors; at MC conditions government still takes over 100 per cent of the rents on all fields.

The analysis of the behaviour of the fiscal system under the collapsed-price scenario has been conducted after taking account of the abolition of the domestic-market obligation in 1986. With the government share of profit oil at 72 per cent, the fiscal system in money-of-the-day terms is very mildly progressive on the HV field, proportional on the MV one, and regressive on the LV and IVLV ones. The results are shown in Figure 6.23. The shape of the curves owes much to the incidence of the signature and production bonuses, which are unrelated to field profitability. At low overall levels of project profitability their impact on the smaller fields is sufficient to increase the tax take as costs increase.

With the 1986 collapsed-price scenario, at a 10 per cent real discount rate under LC conditions on all fields, the government takes exceed 100 per cent of the economic rents, usually by a very small margin. At a 5 per cent discount rate at LC conditions the MV and LV fields produce takes of nearly 94 per cent, while on the IVLV one it is 97.4 percent; at MC conditions takes exceed 100 per cent by significant margins. As concluded above, government takes in the Indonesian system are fairly sensitive to discount rates employed. The strong influence of the discount rate may be attributed to the (effective) ring-fence provisions which, in conjunction with the moderate rate of depreciation permitted, result in a rather long period required for the recovery of costs.

Because of the continuing uncertainties surrounding the Indonesian legislation, it was thought useful to consider the working of a system which incorporated the new income-tax legislation, no domestic-market obligation, and a government share of profit oil of 65.909 per cent. This system produces a government take in money-of-the-day terms of approximately three percentage points below that shown in Figure 6.23 for all field sizes and cost conditions. At a 10 per cent discount rate the government's share of economic rents under LC conditions is 97.9 per cent on the MV field and 94.9 per cent on the LV one; the take just exceeds 100 per cent on other fields. At a 5 per cent discount rate, government take ranges from 90 to 94 per cent across the most likely field sizes under LC conditions; it exceeds 100 per cent under MC conditions.

When the position facing an explorationist in Indonesia is considered, adjustments need to be made for the fact that, in Indonesia, exploration costs can be less than in the North Sea. Accordingly, the effects of the fiscal system shown in Table 6.6 (for the 1985 price perspective) are for a program of $5 million.

It is seen from Table 6.6 that pre-tax EMVs are generally healthily positive, but post-tax values are negative under discount rates of 10 per cent and above and tax takes correspondingly high. This result comes about from the combination of the high nominal tax rates on discovered fields with the operation of the effective ring fence around each contract area, which restricts the timing of relief for exploration costs. The government does not share in the initial exploration costs before production commences and so, in present-value terms, the burden on the investor is significantly increased. When EMVs are positive by comparatively small amounts, the fiscal system can readily extract more than 100 per cent of all the expected rents and thus impair exploration.

With exploration programs costing $20 million, pre-tax EMVs remain positive under all the success rates and discount rates employed. On a post-tax basis, however, EMVs are generally transformed to negative values. Effective tax takes in discounted terms are correspondingly high.

Under the 1986 oil price perspective, an exploration program of $5 million yields pre-tax EMVs which are positive under all the success rates and discount rates employed. On a post-tax basis EMVs become negative at success rates of 1 in 10 with discount rates of 5 per cent; at a 1 in 5 success rate they are positive at a 5 per cent discount rate. With an exploration program of $20 million, pre-tax EMVs are positive under all discount rates with a success rate of 1 in 5, at the 10 per cent rate with a success rate of 1 in 10, and at the 5 per cent rate under success rates of 1 in 20. Post-tax EMVs for this size of exploration program are negative under all the success rates and discount rates used.

In sum, the Indonesian fiscal system is only modestly responsive to changes in the operating environment. Although its main elements are related to profits, disincentive effects can readily emerge. The availability of only moderate rates of recovery of costs for production-sharing and income-tax purposes means that the system is regressive in present-value terms and thus not well targeted on economic rents. Given the high nominal and effective rates, the result is that the scheme can collect more than 100 per cent of the rents. The abolition of the domestic-market obligation has improved the efficiency of the system.

Table 6.6
Indonesia
Expected Monetary Values and Government Takes facing Explorationist, $5 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	371.9	22.1	89.5
5	233.2	8.1	94.0
10	147.8	-0.4	100.4
15	93.1	-5.8	109.9
Overall Discovery Rate: 1 in 10			
0	183.4	8.5	91.7
5	114.0	1.4	97.8
10	71.1	-2.9	107.1
15	43.7	-5.8	121.8
Overall Discovery Rate: 1 in 20			
0	89.2	1.8	96.4
5	54.4	-1.9	106.4
10	32.8	-4.2	123.4
15	18.9	-5.8	155.8

When the position of the explorationist is considered, the comparatively long wait required before exploration costs are recovered for both income-tax and production-sharing purposes exacerbates the inefficiency of the system. The government does not share exploration risks to a high degree and, given the high tax rates, exploration incentives are likely to be impaired.

Figure 6.20
Indonesia
Government Share of Economic Rents (at World Prices), 10% Real Discount Rate
1986 Price Perspectives

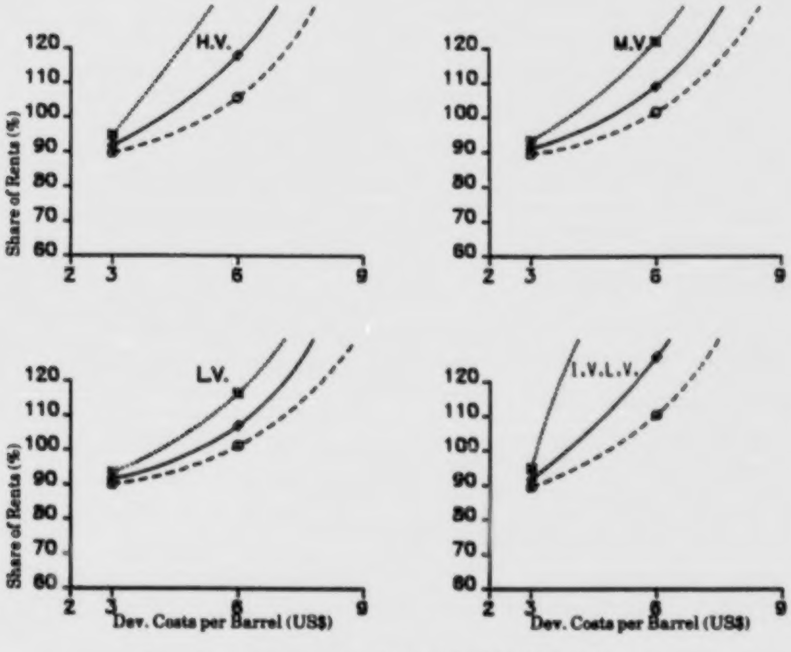


Figure 6.21
Indonesia
Government Share of Economic Rents (at DMP), 10% Real Discount Rate
1985 Price Perspectives

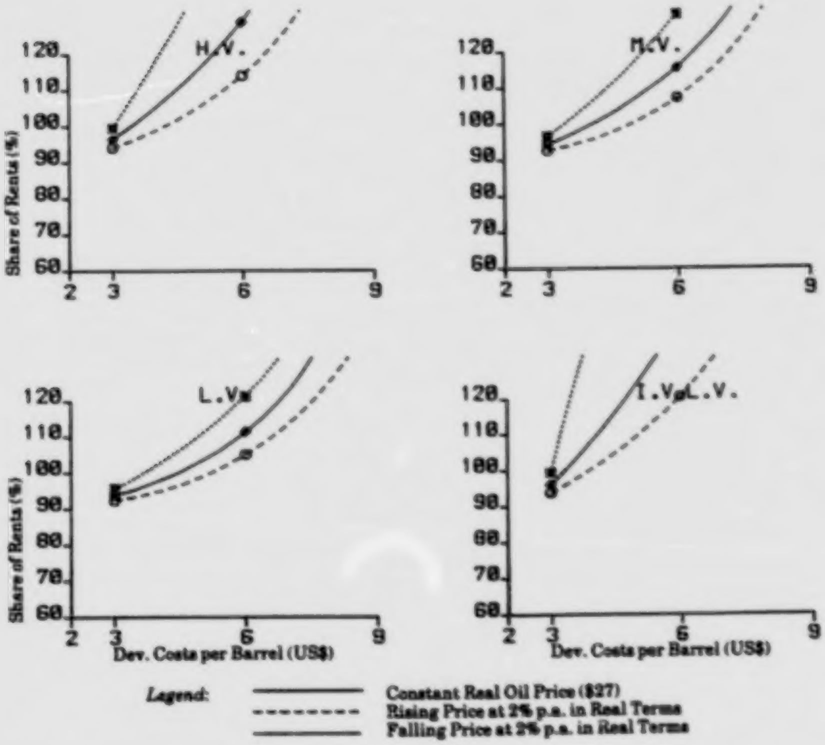


Figure 6.22
Indonesia
Government Share of Economic Rents (at World Prices), 15% Real Discount Rate
1985 Price Perspectives

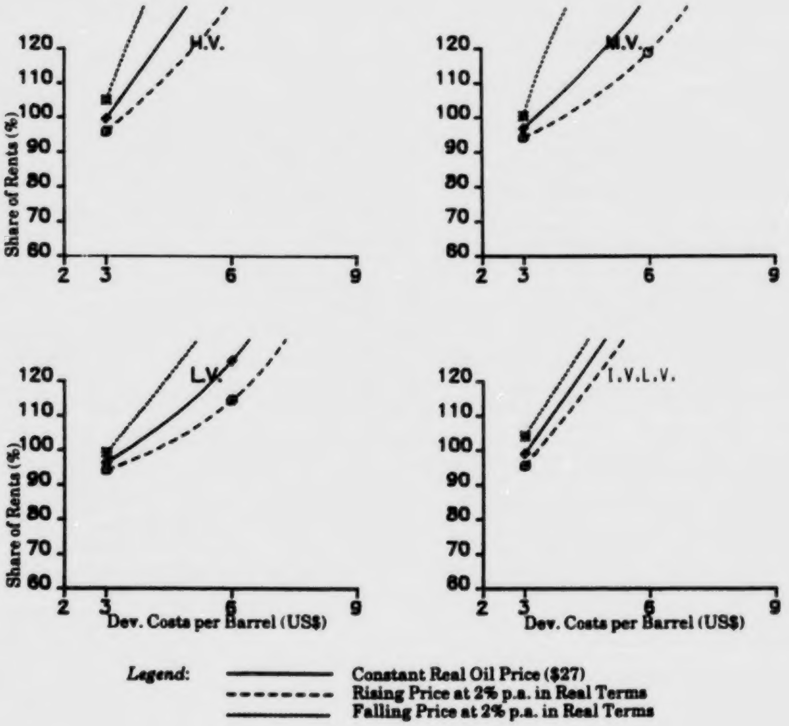
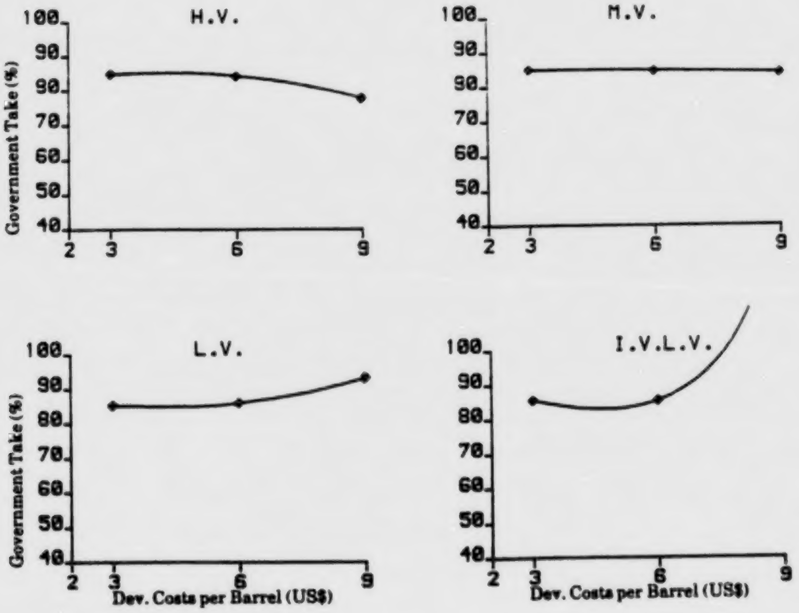


Figure 6.23
Indonesia
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(5) Malaysia

The Malaysian fiscal system considered here is that as modified in December 1985, with a cost-recovery ceiling of 50 per cent. In Figure 6.24 the share of economic rents accruing to the government through the fiscal system is shown for a 10 per cent discount rate under the oil price scenarios expected in 1985. The results show that the fiscal system is regressive and extracts very high shares of economic rents. The most likely cost conditions for new offshore operations in Malaysia are LC, or development costs of around $3 per barrel; in these circumstances the investor receives a modest share of the economic rents. The operation of the sliding-scale mechanism for sharing profit oil is seen to ensure that the investor obtains a rather higher share of the rents on the smaller fields.

As development costs increase above $3 per barrel, the tax take increases at a fast pace. This is particularly the case under the falling real price scenario: the system is distinctly regressive in relation to oil price changes. The effective burden of the royalty increases as profitability falls. Further, the 50 per cent ceiling on the recovery of costs for production-sharing purposes becomes more burdensome the lower the level of profitability. When profitability is "high" the ceiling is less likely to be operative than when it is "low". Postponement of cost recovery through the operation of the ceiling increases the effective burden of the fiscal system in present-value terms. Similarly, the comparatively "slow" depreciation provisions for tangible items of capital expenditure help to increase the effective fiscal take.

Figure 6.25 shows the total share accruing to the government when participation by Petronas is added. At LC conditions the state's share increases significantly. As costs increase, however, the system becomes less regressive under every price scenario. Petronas is sharing in present-value "losses" as well as in profits.

The government take is quite sensitive to the discount rate employed. At a 15 per cent discount rate, as shown in Figure 2.26, the tax take is seen to be very regressive and severe. A combination of the high nominal rates and the fairly slow pace of depreciation produces this result.

Under the collapsed oil price the system becomes still more severe. At a 10 per cent discount rate under LC conditions, the tax take is 97.4 per cent on the MV field and 94.1 per cent on the LV one; on other fields the take exceeds 100 per cent. At a 15 per cent discount rate the take exceeds 100 per cent under LC conditions. The take in money-of-the-day terms is shown in Figure 6.27. It is seen to be in the range of 85 to 86 per cent under LC conditions on all fields except the VLV one, where it is 78 per cent. The system is regressive in nominal terms.

In general the Malaysian system is not well directed to its target and is not sufficiently sensitive to the major changes in the operating environment which have taken place in the 1985-1986 period. A combination of production-based levy, fairly slow depreciation rates, and high nominal rates of tax produces an overall system which is not sufficiently related to project profitability in present-value terms to prevent investment disincentives from emerging.

The position of the explorationist with a $20 million program under the 1985 oil price perspective is seen in Table 6.7. It is seen that pre-tax EMVs are positive under all the scenarios examined. After tax and state participation EMVs remain positive only under situations of low discount rates. The present value of the expected tax take is very high, reflecting the comparatively slow pace of recovery of costs. Under exploration programs costing $5 million, the pre-tax

Table 6.7
Malaysia (State Participation Included)
Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Total Government Take (%)
	Pre-Tax	Post-Tax and Participation	
Overall Discovery Rate: 1 in 5			
0	356.9	33.6	87.8
5	217.5	11.8	90.8
10	131.2	-1.4	96.0
15	75.7	-9.7	104.7
Overall Discovery Rate: 1 in 10			
0	168.4	11.3	89.2
5	98.2	0.1	93.5
10	54.6	-6.8	101.3
15	26.3	-11.2	116.4
Overall Discovery Rate: 1 in 20			
0	74.2	0.1	92.3
5	38.6	-5.7	99.8
10	16.3	-9.4	116.1
15	1.6	-12.0	162.0

EMVs are all healthily positive. After tax and participation the pattern displayed under the $20 million program is repeated though, of course, the absolute size of the negative EMVs is considerably smaller.

Under the collapsed oil price, with a $20 million exploration program, pre-tax EMVs are positive with a 1 in 5 chance of discovery at all discount rates considered; with lower chances of success they turn negative at higher discount rates. After tax and state participation EMVs are negative under all but extremely favourable circumstances regarding success rates.

In sum, the Malaysian fiscal system displays a considerable lack of sensitivity to changes in the operating environment. The scheme is structurally not well directed at economic rents. Production-based levies are combined with income tax with a fairly slow rate of recovery of costs and, together with the high rate of nominal take, the result is that the scheme is not very accurately targeted on economic rents. Investment disincentives are likely to occur unless cost conditions and prospectivity are very favourable. The Malaysian scheme shares in the investment risks to only a moderate extent, and this feature can also contribute to the production of disincentives.

Figure 6.24
Malaysia (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

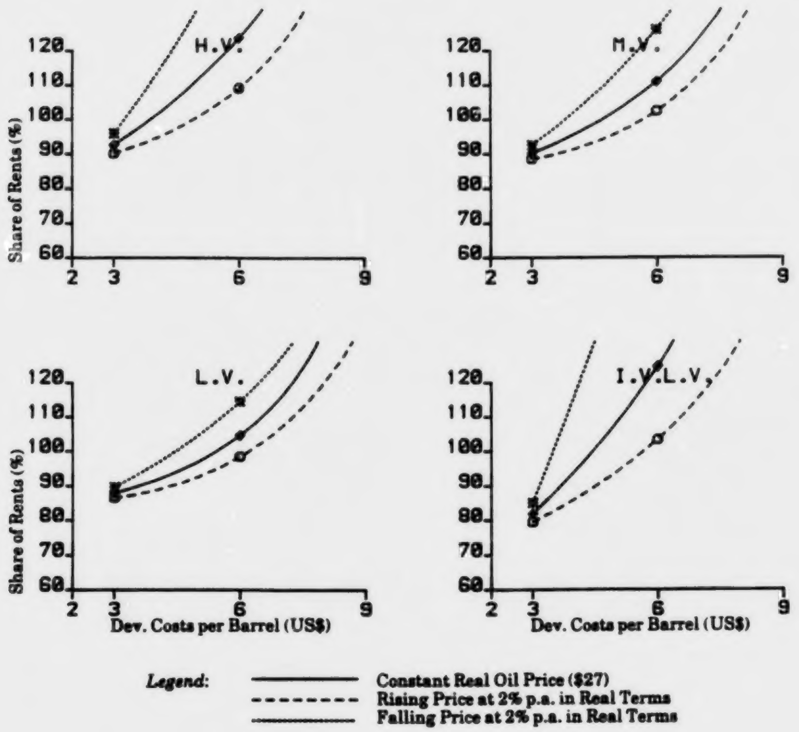


Figure 6.25
Malaysia (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

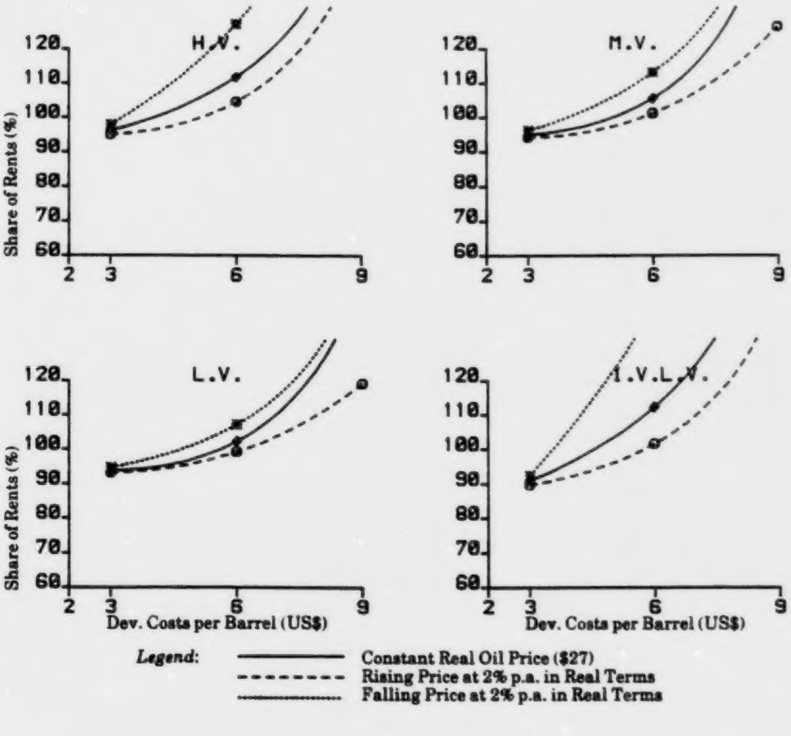


Figure 6.26
Malaysia (Tax Only)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

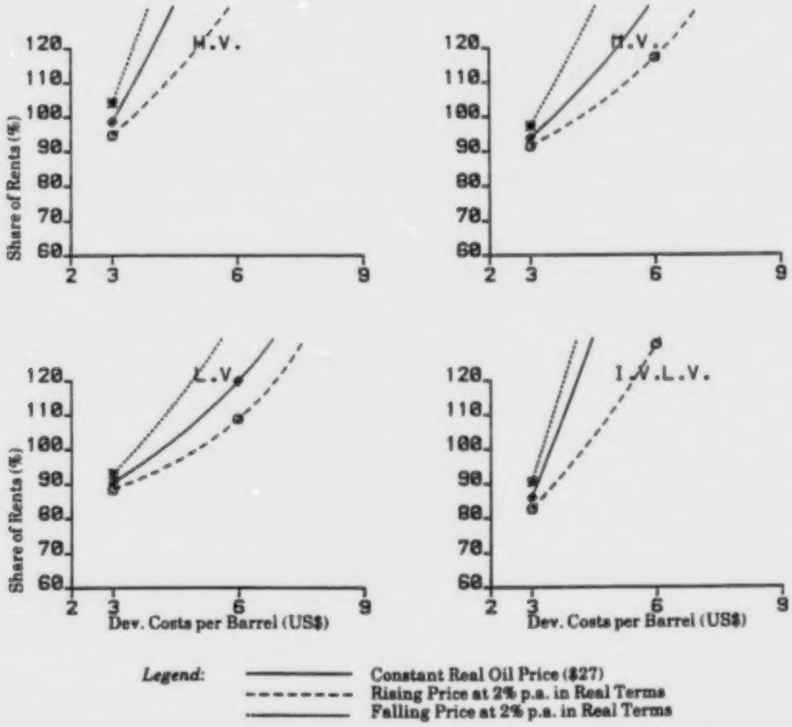
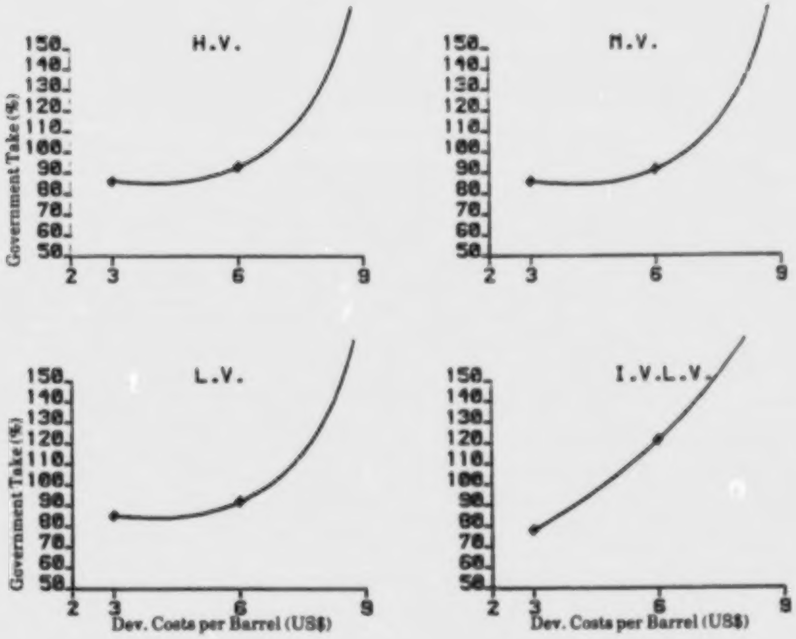


Figure 6.27
Malaysia (Tax Only)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(6) China (Offshore)

The Chinese government's shares of economic rents collected through the tax system under the 1985 oil price perspectives are shown in Figure 6.28 for a 10 per cent discount rate. The system is seen to be regressive with respect both to oil price changes and cost increases. On the three oil price scenarios considered, the level of the take (from taxes only) is between 70 per cent and 80 per cent at LC conditions on all fields except the IVLV one, where it is between 45 per cent and 50 per cent. The royalty relief and profit oil concession for marginal fields explain the markedly lower burden in this case. For any given level of cost per barrel, the sliding-scale profit oil split makes the take vary directly with field size.

The regressive nature of the fiscal system is explained by several of its features. The royalty and the Industrial and Commercial Tax obviously introduce a regressive element, especially in present-value terms. Depreciation of development costs is on a six-year straight-line basis. It is assumed that, as China is a new province for petroleum exploitation, investors will not have other existing income against which they can set their allowances for field development costs; accordingly, the investor has to wait a considerable time after incurring expenditure before relief is obtained. The cost-recovery provisions for production-sharing purposes stipulate a 50 per cent ceiling on revenues eligible for use for development cost recovery; this tends to make the system regressive in present-value terms. The ring-fence provision also contributes, although the ability to compound forward unrecovered development costs at 9 per cent interest mitigates this problem to some extent.

Development costs are likely to be $6 per barrel in some parts of the Chinese Continental Shelf. In these circumstances the tax take under constant real and rising real prices is generally under 100 per cent, especially on the IVLV field, but under falling real prices it can exceed 100 per cent on the HV and MV fields. When state company participation is added (Figure 6.29), total government take is seen to increase significantly on all fields. The fiscal system is less regressive over the complete cost range if CNOOC always takes up its option to participate and shares in present-value losses as well as gains.

As with other similar forms of fiscal systems the degree of regressiveness of the Chinese system is fairly sensitive to the discount rate employed. At a 5 per cent discount rate under falling real prices, the take on the MV/MC field is 86.3 per cent, on the LV/MC one 86.2 per cent, and on the IVLV/MC one 64.8 per cent. At a 20 per cent discount rate the takes on all these fields greatly exceed 100 per cent.

In money-of-the-day terms the take is virtually proportional in the LC to MC range on all sizes of fields but regressive in the MC to

HC range. The substantial element of production-based levy is responsible for this outcome.

Under the collapsed-price scenario the Chinese system becomes more regressive and produces a higher level of take. Figure 6.30 illustrates this in money-of-the-day terms. At lower levels of profitability the impact of levies based on gross revenues becomes more serious. In present-value terms the result is that the tax take at a 10 per cent discount rate under LC conditions is 84 per cent on the HV field, 78.7 per cent on the MV one, 88.7 per cent on the LV one, and 101.1 per cent on the IVLV one; under MC conditions the take greatly exceeds 100 per cent on all fields. At a 15 per cent discount rate the HV and MV fields are the only ones which remain viable to investors. At a 5 per cent discount rate under LC conditions, the fields have takes in the 74 to 76 per cent range, except the IVLV one which is only 48 per cent; at MC conditions takes exceed 100 per cent on all fields.

The effect of the system on an explorationist contemplating a program of $20 million under 1985 oil price scenarios is shown in Table 6.8. It is seen that the pre-tax EMVs are positive under all probabilities of discovery and discount rates. Post-tax and participation EMVs are positive under the 1 in 5 chance of discovery except at the 15 per cent discount rate; they are negative at 10 per cent and higher discount rates for chances of discovery of 1 in 10; for 1 in 20 chances they are negative at discount rates of 5 per cent and above. The conclusion is that exploration incentives are impaired by the fiscal system. There is little risk sharing by government. Given the requirement that the investor has to wait for relief for his exploration costs until production from discoveries relating to that exploration is achieved, the disincentives might in fact be expected to be greater than they are. The relatively low tax burden on LC fields helps to reduce them.

With a less costly exploration program of only $5 million, there is a considerable transformation in the picture. Pre-tax EMVs are healthily positive under all the success rates and discount rates examined, and post-tax and participation EMVs are now positive except under 15 per cent discount rates. The post-tax position is sensitive to the size of the exploration costs because of the delay in obtaining relief for the expenditures. With a $60 million exploration program under the same oil price, the disincentive effects of the fiscal system increase noticeably. The lack of front-end relief becomes progressively more important the greater the size of the outlays involved.

Under the scenario of collapsed oil prices, pre-tax EMVs for a $20 million program remain positive at all discount rates with a 1 in 5 chance of discovery. At the 1 in 10 chance the EMV is negative only at the 15 per cent discount rate, and with a 1 in 20 chance it is negative at the 10 per cent discount rate as well. On a post-tax and participation basis EMVs are negative under all the success rates and discount factors employed. The dramatic effect of the fiscal system on EMVs is to a considerable extent due to the requirement on the investor to wait for relief for these costs. With an exploration program costing only $5 million, pre-tax EMVs are positive under all the situations examined; on a post-tax base there are some positive EMVs under favourable prospectivity and low discount rates.

Table 6.8
China (State Participation Included)
Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)	
	Pre-Tax	Post-Tax and Participation	Tax	Total
Overall Discovery Rate: 1 in 5				
0	367.3	45.3	69.1	87.6
5	225.1	16.2	75.6	92.8
10	137.2	-2.1	86.3	101.5
15	80.6	-14.0	105.6	117.4
Overall Discovery Rate: 1 in 10				
0	173.6	12.7	73.1	92.7
5	102.0	-2.4	83.4	102.4
10	57.5	-12.1	102.9	121.0
15	28.7	-18.6	148.2	164.8
Overall Discovery Rate: 1 in 20				
0	76.8	-3.7	82.6	104.8
5	40.5	-11.7	105.0	128.9
10	17.7	-17.1	166.9	196.3
15	2.8	-20.9	766.7	852.3

In sum, the Chinese fiscal system, like others with a similar structure, is regressive in nature, not well targeted on economic rents, and so not well adapted to deal with major changes in the operating environment. The economic distortions brought about are not as great as in some other countries because the take at high levels of profitability is not very high. With exploitation in deeper waters disincentives are likely to be produced – for new investors there is not a high degree of risk sharing incorporated in the system; thus, exploration incentives are highly sensitive to the likely cost of the exploration program.

Figure 6.28
China (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

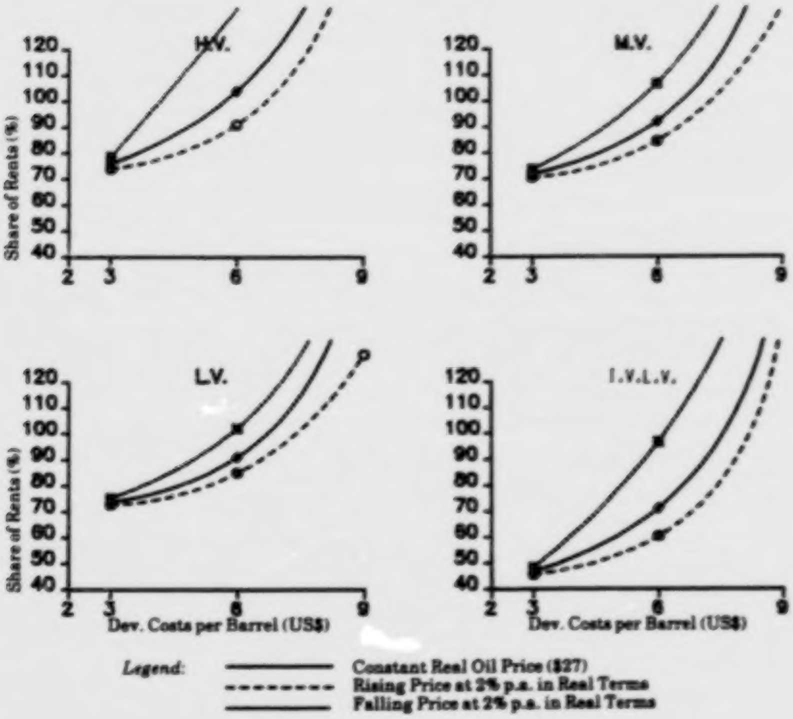


Figure 6.29
China (State Participation Included)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

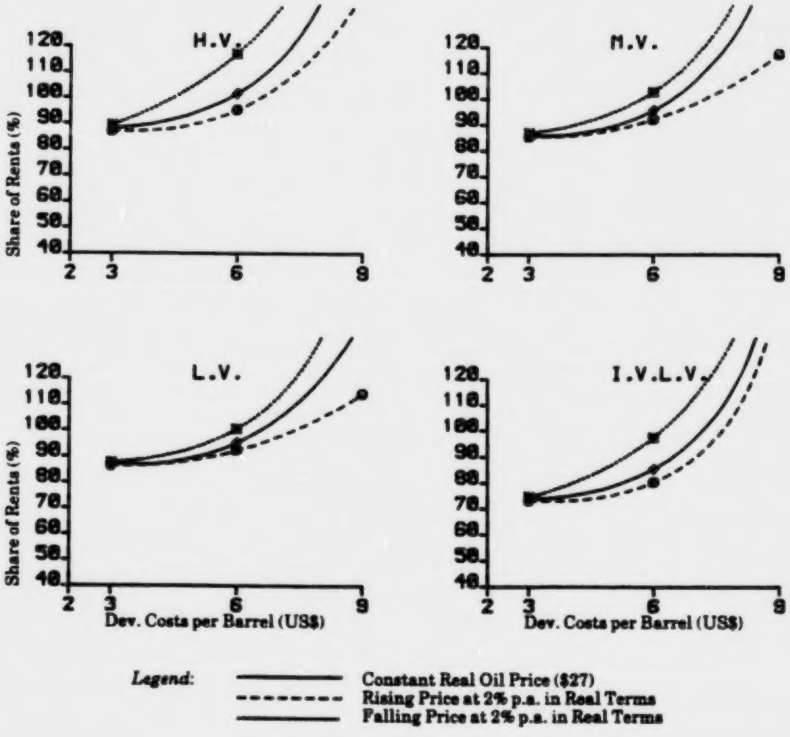
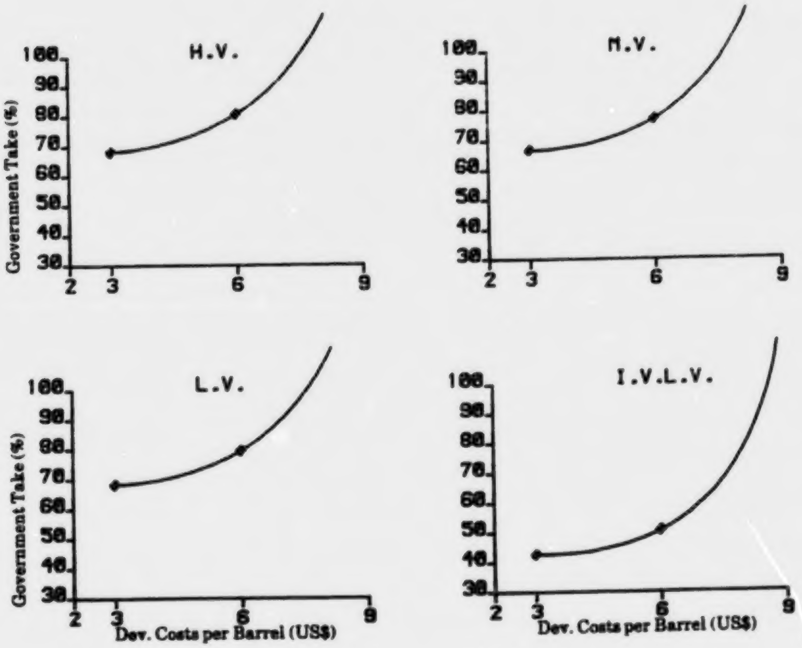


Figure 6.30
China (Tax Only)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(7) Egypt

The share of economic rents accruing to the Egyptian government under the 1985 oil price perspectives for a 10 per cent discount rate are shown in Figure 6.31. The fiscal system is seen to be regressive with respect to both oil price and cost changes and collecting very high shares of the economic rents. In Egypt exploitation costs are comparatively low; in most locations LC conditions would prevail. The government's share of rents is thus in excess of 90 per cent under all the 1985 oil price scenarios and the take increases at a fairly fast pace as costs rise. At a 15 per cent discount rate, as is shown in Figure 6.32, the system becomes distinctly more regressive and the level of take higher. Under falling real prices the take exceeds 100 per cent at LC conditions. The system is very sensitive to the discount rate employed.

In money-of-the-day terms the scheme is broadly proportional with respect to both oil price and cost changes. The level of take is in the 80 to 85 per cent range depending on field size.

Because of the progressive scheme for sharing profit oil, the take increases with field size. The ceilings on the amount of oil available for cost-recovery purposes are responsible for the regressive nature of the system in present-value terms – at lower levels of profitability the ceiling factor extends the time required to recover costs; this keeps up the government's take and reduces returns to investors. It will be remembered that the investor is treated essentially on an individual project basis in Egypt. This is another factor that ensures that the system is regressive. Thus, even though the scheme is based on profits, the timing of cost recovery under the production-sharing arrangement makes it regressive. The combination of this with a high nominal tax rate means that the fiscal system is both severe and highly regressive at discount rates normally employed by investors.

Under the collapsed-price scenario, government takes at a 10 per cent discount rate exceed 100 per cent under LC conditions on all fields. At a 5 per cent discount rate government takes under LC conditions are 93.4 per cent on the HV field, 92.2 per cent on the MV one, 93.1 per cent on the LV one, and 101.5 per cent on the IVLV one; at MC conditions government take exceeds 100 per cent on all fields. The system remains broadly proportional in money-of-the-day terms on all fields except the IVLV (see Figure 6.33). At very low levels of profitability the signature and production bonuses can have a noticeable effect on the total tax take. The ceiling on revenues available for recovery of costs can also mean that some costs may not be recouped at all.

The effects of the Egyptian fiscal system on an explorationist contemplating a program of $5 million under 1985 oil price expectations are shown in Table 6.9. Pre-tax EMVs are healthily positive, but the fiscal system produces very high expected tax takes and converts some outcomes from positive to negative. This results from the time lags in the recovery of exploration costs plus the high government take on discoveries. With an exploration program of $20 million, pre-tax EMVs are generally positive under all the situations examined. After tax, however, they are positive only under extremely favourable assumptions regarding prospectivity with low discount rates. The expected tax takes are very high indeed. Post-tax EMVs are extremely sensitive to the size of the exploration program because of the delay in obtaining relief for the exploration costs.

Table 6.9
Egypt
Expected Monetary Values and Government Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	244.5	17.4	88.0
5	155.9	5.8	93.8
10	100.0	-1.2	102.0
15	63.5	-5.6	-
Overall Discovery Rate: 1 in 10			
0	119.8	6.2	91.2
5	75.3	0.3	99.4
10	47.2	-3.4	111.9
15	28.8	-5.7	-
Overall Discovery Rate: 1 in 20			
0	57.4	0.6	98.1
5	35.0	-2.5	112.6
10	20.9	-4.4	138.9
15	11.5	-5.7	-

Under the collapsed-price scenario, pre-tax EMVs under the $20 million program are positive at all discount rates considered at the 1 in 5 chance of discovery; at the 1 in 10 chance, positive EMVs are found with discount rates up to 5 per cent; at the 1 in 20 chance, all EMVs are negative. Post-tax EMVs are all negative for a $20 million program. Even with the $5 million program the post-tax EMVs are negative except under highly favourable assumptions concerning prospectivity and at very low discount rates.

In sum, the Egyptian system is regressive in its incidence and produces a very high level of government take. While the scheme is based on profits, the restrictions on the recovery of costs mean that it is not well related to economic rents and is highly regressive in present-value terms. It is insufficiently flexible to changes in the operating environment to prevent disincentives from emerging. The recently announced scheme, which puts even greater emphasis on bidding by investors, will certainly result in offers being made at levels below those typical in current arrangements.

Figure 6.31
Egypt
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

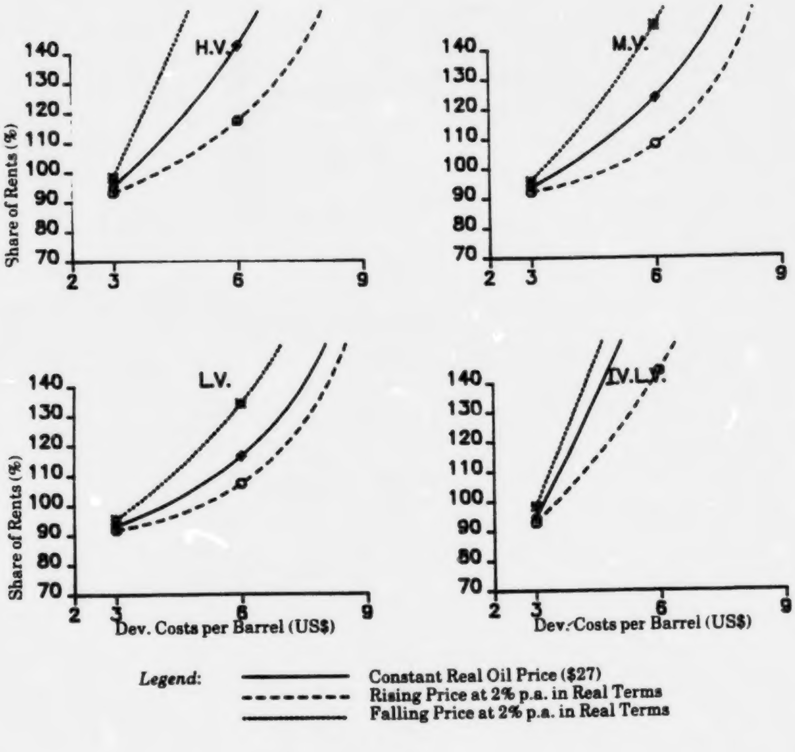


Figure 6.32
Egypt
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

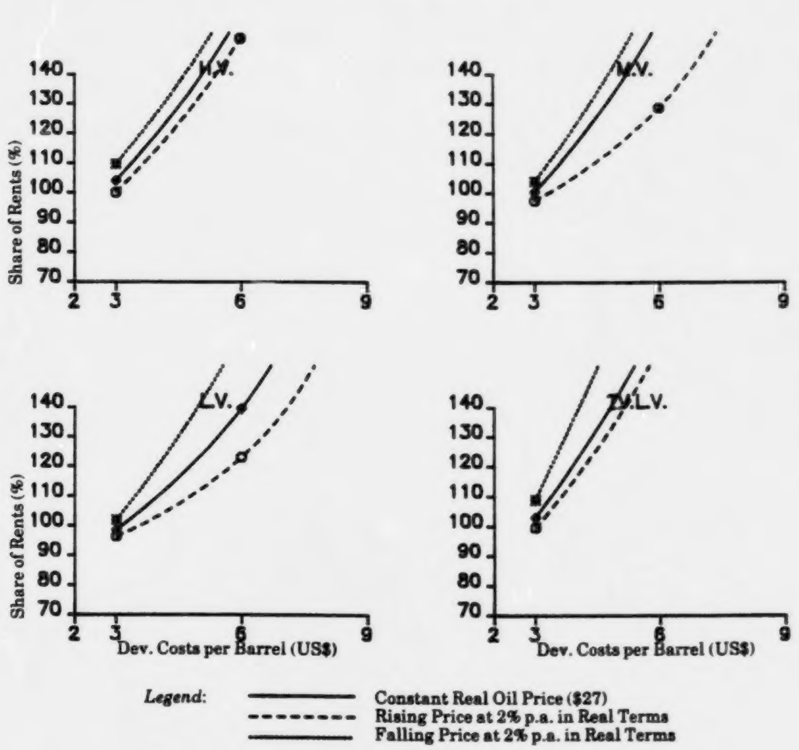
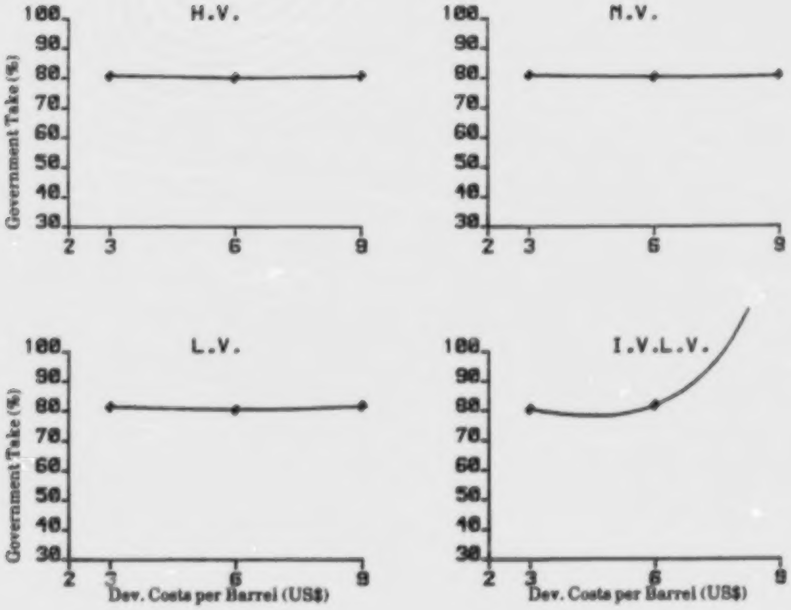


Figure 6.33
Egypt
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(8) Nigeria

Figure 6.34 shows the share of economic rents accruing to the Nigerian government through the tax system ruling in 1985 before the oil price slide, for a discount rate of 10 per cent. It is seen that at LC conditions (the most likely situation in Nigeria) the discounted tax take is between 80 per cent and 90 per cent on all fields. The system is moderately regressive with regard to exploitation costs, but it is noteworthy that the degree to which this occurs is considerably less than in some other countries. It is also noteworthy that at LC conditions the take is progressively related to changes in oil prices: it is lowest under the scenario of falling oil prices.

There are several explanations for these phenomena. The posted-price formula (discussed in Chapter 3) contains a deduction of a fixed profit margin per barrel; the lower the profitability of the project the greater the *relative* value of this allowance. The posted price is employed to determine both royalty and income-tax payments. The presence of this element in the factors determining the base of the payments makes the system broadly proportional, in money-of-the-day terms, with respect to cost changes and progressive with respect to oil price changes. Also, ongoing investors in Nigeria benefit by being able to set allowances relating to new field developments against existing income. With intangible drilling costs being expensed, this concession is very valuable in present-value terms. This facility helps to make the fiscal system less regressive, or more progressive, than it otherwise would be, as the concession is relatively more valuable as costs increase.

As a consequence of the operation of these factors the Nigerian system at a 10 per cent discount rate is modestly regressive over the LC to MC range. The take is less than 100 per cent of the economic rents at MC conditions on all fields except the IVLV one under falling real prices. As costs continue to increase, however, the system becomes more regressive with respect to both oil price and cost movements.

The system is generally more regressive under the 15 per cent discount rate (Figure 6.35). The takes are still all comfortably below 100 per cent on LC conditions and the system is still progressively related to oil prices at that level of costs. At the MC level the system collects just under 100 per cent of the rents on the MV and LV fields, but on the IVLV one disincentives to invest are prevalent.

The addition of state participation (Figure 6.36, for a discount rate of 15 per cent) increases total government take at LC conditions to around 95 per cent on all fields. The differences between the government takes for the various price scenarios are reduced with the inclusion of the state company's net profits: concessions through the tax system are partially recouped in higher net profits to the state company. The system as a whole is less regressive with regard to cost changes, as the state company is effectively sharing in present-value losses under the higher levels of cost.

In late 1985 and 1986 the Nigerian government introduced a new fiscal system designed to deal with the new levels of oil prices. The effects of this complicated system depend to a large extent upon the relationship between the official price and the realized price. If the official price is equal to the realized market value, the system behaves very similarly to the old scheme. Under the scenario of collapsed oil prices, the share of economic rents accruing to the government from the tax system, with a 10 per cent discount rate under LC conditions, is 77 to 78 per cent across the range of fields considered. Under MC conditions the take is 85.1 per cent on the MV one and 79.8 per cent on the LV one; on other fields it exceeds 100 per cent. At a 15 per cent discount rate the takes are in the 90 to 92 per cent range across the relevant fields at LC conditions. Under MC conditions they are in the 92 to 94 per cent range on the MV and LV fields.

As Figure 6.37 shows, the system is generally progressive in nominal terms in relation to cost changes under the collapsed-price scenario. For the ongoing investor there are very significant benefits in the form of front-end reliefs on development costs relating to new fields, and these turn out to be strong enough to outweigh the increasing burden of the royalty as costs increase. The high rate of tax, of course, boosts the value of the front-end reliefs.

When the official price equals the realized price under the scheme devised in 1985-1986, the tax take is not very different from that under the earlier system. Under that scheme the posted price falls close to the realized value when market levels are "low." If incentives in the form of a PPT credit are to be earned, there needs to be a significant differential between the official price and the realized value. A differential of around $4 is necessary before the credit is sufficient to bring the revised government take below the take calculated at the official price.

The position of the explorationist in Nigeria is summarized in Table 6.10 for a program of $20 million under the 1985 oil price perspective. The results show that under the pre-tax situation EMVs are generally positive. The effects of the fiscal package (tax and state participation) are to transform several of the outcomes from positive to negative, since the expected tax takes are very high. Exploration is attractive only under favourable prospectivity and low discount rates. With an exploration program of $10 million, pre-tax EMVs are healthily positive under all the scenarios examined; after tax and participation they remain positive under all the scenarios except where the chance of discovery is only 1 in 20 and discount rates are 10 per cent or more. With a $5 million exploration program, post-tax EMVs are positive under all the scenarios.

Table 6.10
Nigeria (State Participation Included)
Expected Monetary Values and Total Government Takes facing Explorationist, $20 Million Program
Constant Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Total Government Take (%)
	Pre-Tax	Post-Tax and Participation	
Overall Discovery Rate: 1 in 5			
0	229.5	10.7	94.8
5	140.1	5.0	96.0
10	83.4	1.4	98.1
15	46.1	-1.0	102.5
Overall Discovery Rate: 1 in 10			
0	104.8	3.8	95.8
5	59.6	0.9	98.2
10	30.7	-1.0	103.6
15	11.5	-2.3	123.7
Overall Discovery Rate: 1 in 20			
0	42.4	0.4	98.8
5	19.3	-1.1	107.2
10	4.3	-2.1	195.0
15	-5.8	-2.9	

Under the collapsed oil price, pre-tax EMVs for a program of $20 million are positive in all but four of the scenarios considered. The tax system reduces the positive EMVs very considerably but, interestingly, there are no conversions from positive to negative values. This result emanates from the very valuable benefits of the front-end tax reliefs on exploration expenditures. With a tax rate of 85 per cent and tax relief being available on a 100 per cent first-year basis, the present value of this shelter is very high and has a substantial influence on the total EMV calculation.

The Nigerian fiscal regime is a combination of orthodox and unorthodox features. It is not directly targeted on economic rents. However, the various special allowances for the income tax do produce for the system a degree of sensitivity which reduces the potentially distorting effects of the other, fairly crude devices, such as the orthodox royalty. The sensitivity is particularly due to the high rate of front-end relief for an ongoing investor with respect to both development and exploration costs. Some distorting effects on investment nevertheless appear likely.

Figure 6.34
Nigeria (Tax Only)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

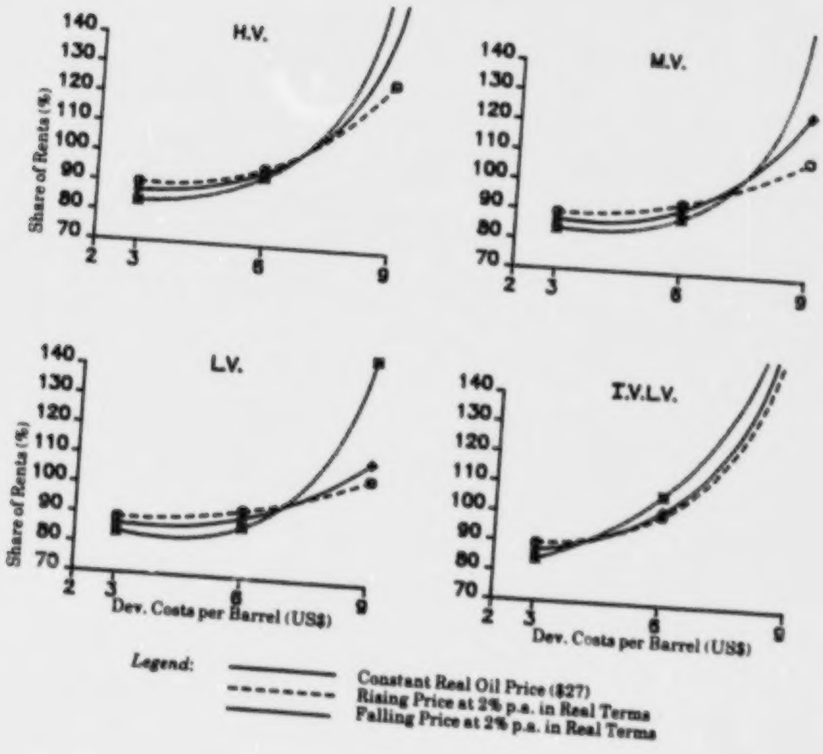


Figure 6.35
Nigeria (Tax Only)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

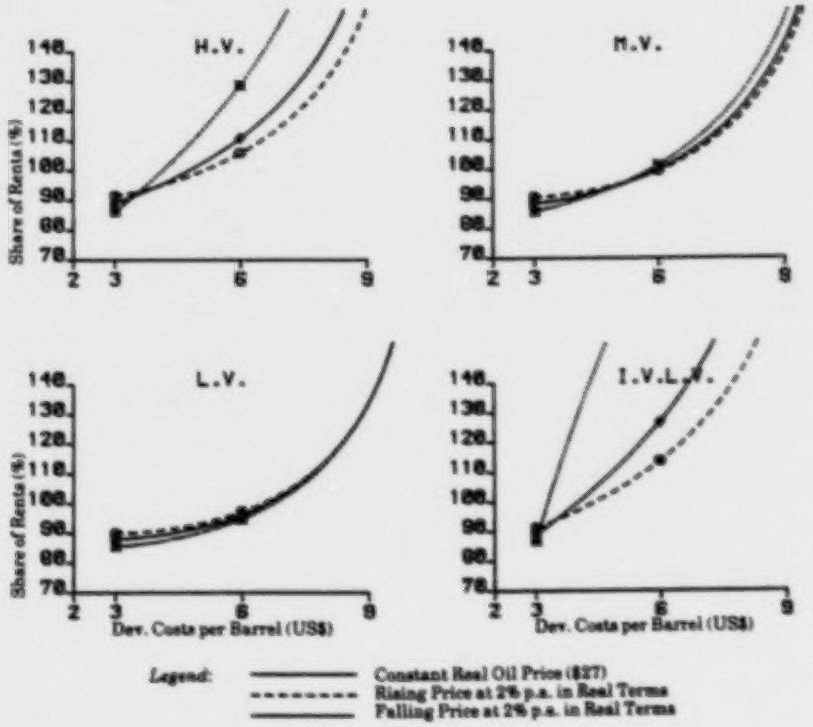


Figure 6.36
Nigeria (State Participation Included)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

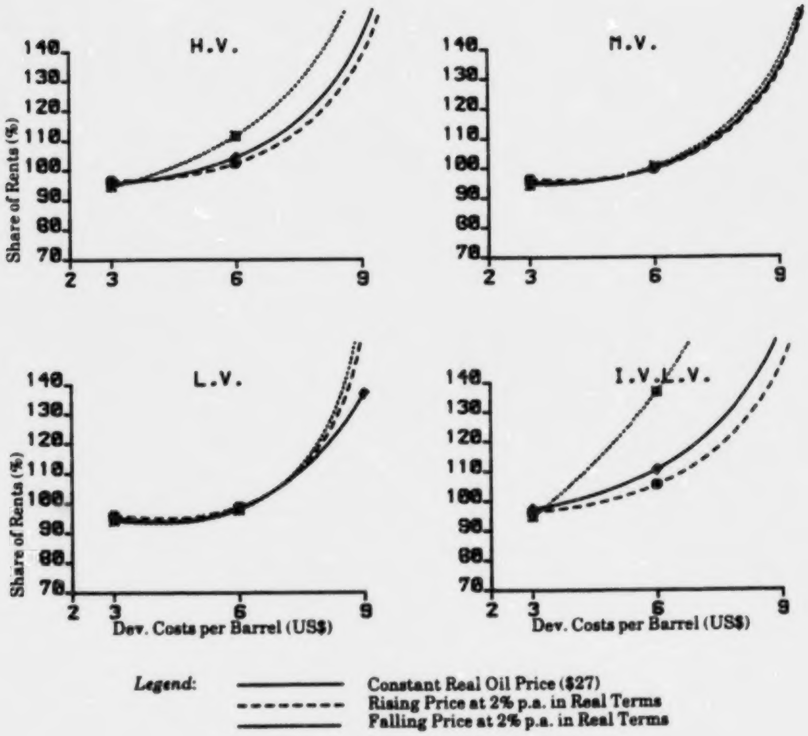
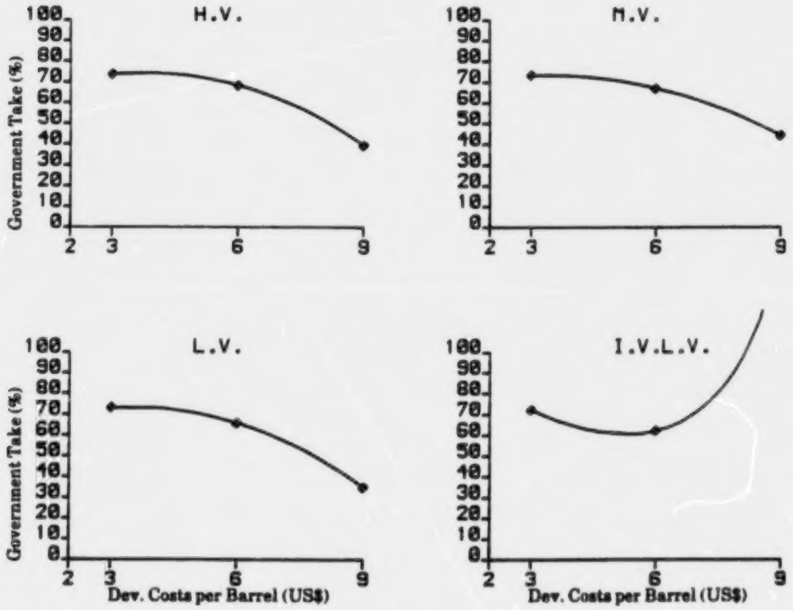


Figure 6.37
Nigeria (Tax Only)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(9) United States

Outer Continental Shelf (California)

The effects of the U.S. tax and royalty system applied to offshore California are shown in Figure 6.38 for a 10 per cent rate of discount under the oil price scenarios expected in 1985. The analysis does not, of course, include bonus bids, which could not be incorporated directly into this type of study. The tax and royalty system is seen to collect 45 to 53 per cent of the rents at LC conditions. The system is regressive with respect to both oil price and cost changes, but under MC conditions the share of rents collected is comfortably below 100 per cent, except on the VLV field at falling real prices. The system is regressive because of the presence of the production-based royalty, the fairly slow rates of depreciation, and, compared with the old system, the lack of investment tax credit. Ongoing investors benefit from the ability to set drilling costs on a new field against other existing income, and this keeps down the government take in present-value terms.

At a 15 per cent discount rate the fiscal system is considerably more regressive, but at LC conditions – the most likely situation – the take is still moderate, being in the 50 to 60 per cent range across all fields and price scenarios. With development costs of $6 per barrel the take is tolerable on the LV field under all oil price scenarios. On the larger field sizes development costs will normally be under $6 per barrel but, if this figure is attained, the take could exceed 100 per cent of the rents and cause investment disincentives. The highly regressive nature of the system at this discount rate is, of course, due to the conventional royalty plus the modest rate of depreciation.

The total share of economic rents collected by the government depends not only on the tax system but also on the bonus bids which have been made by investors as a condition of acquiring leases. How efficient the total system is thus depends on how accurately the bidders were able to forecast the economic rents in question.

Where competition among bidders is strong and where rents are foreseeable, the system can perform efficiently. The bidders would take into account the royalty and tax obligations that have to be met on production and the pace at which costs are allowable against tax. If the bids were made with reasonable accuracy it can be said that the system should operate reasonably efficiently when fields are in the LC to MC range on the oil price scenarios expected in 1985. If fields have costs in excess of MC, the tax system could cause distortions in investment decisions. Bonus bids should reflect the economic rents in excess of the share taken by the tax and royalty system; to the extent that they do not, the whole system does not accurately collect the rents. The results will be that the government obtains more or less than 100 per cent of the total rents, but as long as the fields are in the

LC to MC range it is unlikely that distortions to investment will be caused.

Under the scenario of collapsed oil prices, the share of economic rents taken by royalties and taxes at a 10 per cent discount rate under LC conditions is 59.4 per cent on the HV field, 56.6 per cent on the MV one, 55.6 per cent on the LV one, and 62.3 per cent on the IVLV one. At MC levels the share exceeds 100 per cent on all fields. At a 20 per cent discount rate the share at LC is 70 per cent, 64.3 per cent, and 84.8 per cent, respectively, on the MV, LV, and IVLV fields. The whole system becomes more regressive due to the increased burden of the royalty at low levels of production. The structure of the system in money-of-the-day terms is shown in Figure 6.39, which indicates how regressive it becomes. Under current circumstances the system applied to offshore California can cause disincentives to investment when the fields are exploited in deeper waters.

The position of an explorationist contemplating a program of $20 million under the price expectations of 1985 is summarized in Table 6.11. Again, bonuses are not included. It is seen that the EMVs before tax and royalty are all healthily positive. Post-royalty and tax values are also generally positive except for the 1 in 20 chance of success with a 15 per cent discount rate. The fiscal system narrowly defined thus does not act as a significant impediment to exploration under the 1985 oil price expectations. The EMVs after tax and royalty indicate to investors the size of the bids they can afford to make under the different geological prospectivities and discount rates. Again the accuracy of the overall system depends on how well the bidding system operates.

Thus, to take a specific example, if an investor who has a 10 per cent real rate of discount feels there is a 20 per cent chance of discovery, he would feel able to bid up to around $90 million given the range of field possibilities for the territory outlined in Appendix 6. If the actual outcome of the exploration were favourable and the MV/LC field were discovered, the investor would then expect to achieve a post-tax net present value of just over $1 billion (at 10 per cent real discount rate) from developing the field. The overall result would then be that the investor would have received a very significant share of the *ex post* economic rents. On the other hand, if the outcome of the exploration were the discovery of the VLV/MC field, the investor could obtain a net present value of just over $20 million from developing the field. In that case the payment of a bonus bid of $90 million would mean the government would have obtained well over 100 per cent of the *ex post* economic rents.

When the size of exploration program was set at $60 million, the post-tax and royalty EMVs became negative only at discount rates of 10 per cent and above under the 1 in 20 chance of discovery and at the

15 per cent discount rate under the 1 in 10 chance of success. The finding that the royalty and tax system does not produce many disincentives to explore is thus reinforced.

Table 6.11
U.S. OCS (Offshore California)
Expected Monetary Values and Tax and Royalty Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Tax and Royalty Take (%)
	Pre-Royalty and Tax	Post-Royalty and Tax	
Overall Discovery Rate: 1 in 5			
0	573.1	235.7	57.6
5	338.4	129.6	60.6
10	199.4	65.6	66.3
15	113.2	25.5	77.3
Overall Discovery Rate: 1 in 10			
0	276.6	112.3	58.1
5	158.7	58.7	61.9
10	88.7	26.2	69.7
15	45.0	5.6	87.6
Overall Discovery Rate: 1 in 20			
0	128.3	50.6	59.2
5	68.8	23.2	65.0
10	33.3	6.5	80.0
15	10.9	-4.3	143.5

Under the collapsed oil price the pre-tax EMVs for a $20 million exploration program are positive under all scenarios except under 1 in 10 and 1 in 20 chances of discovery at 15 per cent discount rates. On a post-tax basis the EMVs remained positive with a 1 in 5 and 1 in 10 chance of discovery for interest rates up to 15 per cent; with a 1 in 20 chance of discovery EMVs became negative at all positive real discount rates. The regressiveness of the system is again noteworthy.

Compared with the previous fiscal system there is a greater likelihood of disincentives being produced when exploration is fairly speculative and the chances of discovery not very high. The lack of investment tax credit plays a role here. When prospectivity is favourable, the expected tax take is somewhat lower than under the previous scenario due to the lower rate of income tax on significant discoveries.

Under the collapsed-price scenario bids will, of course, be lower than under the 1985 perspective. With a 1 in 5 chance of discovery and a 10 per cent discount rate, the post-tax EMV is $13.1 million. If the exploration were highly successful and the MV/LC field were discovered, its development would produce a net value of just over $500 million. In this case the investor would still end up receiving a high share of the *ex post* rents. On the other hand, if the exploration resulted in the VLV/MC field being found, the net present value would be -$85 million. In this case the field would not be developed at all though the government would, of course, already have received the bid.

In sum, the royalty and tax features of the system applied to the U.S. Outer Continental Shelf are not very accurately targeted on economic rents. The system is fairly regressive and can cause some distortions to investment under high cost conditions and where geological prospectivity is low. On the most likely field situations the level of take is comparatively low and in general the chances of significant economic distortions arising are very much less than in many other countries. The overall accuracy of the whole system depends considerably on how efficiently the bidding system operates.

Figure 6.38
U.S. OCS (Offshore California)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

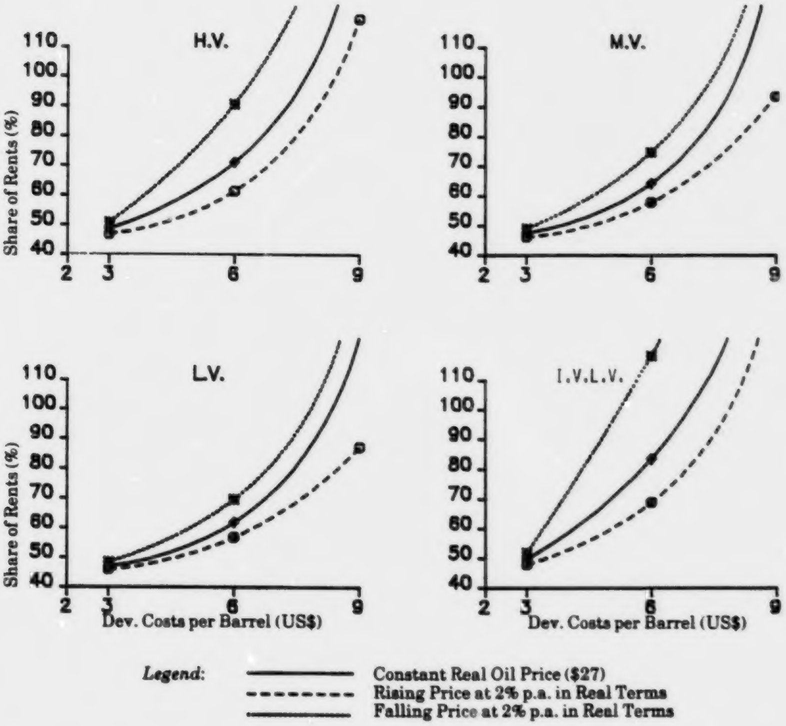
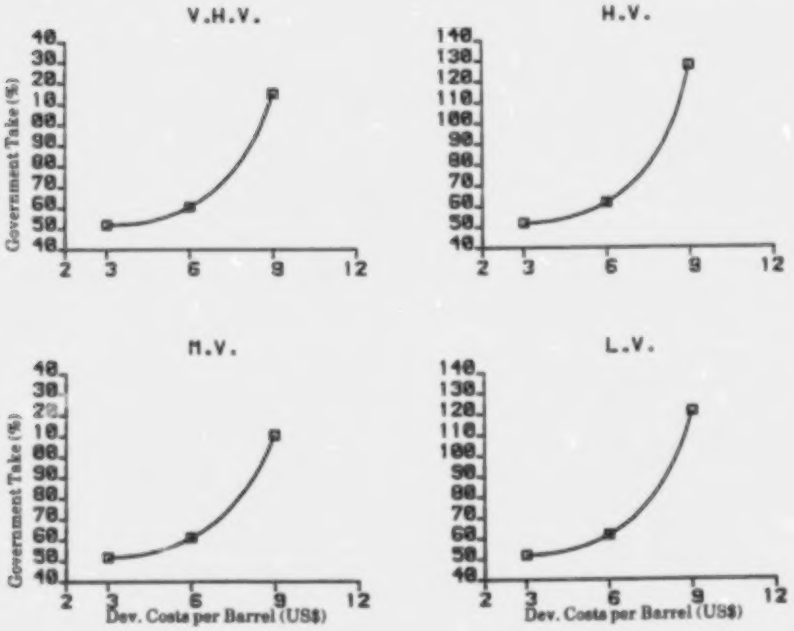


Figure 6.39
U.S. OCS (Offshore California)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



Alaska

Petroleum exploitation in Alaska takes place in several parts of this huge state. The most exciting location is in the northern part. Wellhead values are, of course, considerably lower here due to the great distance from markets. Economic rents from production are correspondingly lower. Part of the rent might in practice be collected by owners of the pipeline to Valdez, though the regulations allow only a utility rate of return. Investors who do not own equity in the pipeline do not have this opportunity. In all the scenarios it was decided to measure the economic rents in the north of the state by making deductions from market values in California for all the transport costs from the North Slope area. In 1985 pipeline transportation charges from the North Slope to Valdez were around $6.20 per barrel and marine tanker costs to markets in California around $3.50 per barrel. Pre-tax economic rents are thus considerably less than for investors receiving world prices.

In Figures 6.40 and 6.41 the pre-tax net values at 10 per cent discount rates are shown under a 1985 oil price perspective and the collapsed oil price, respectively. The development costs refer to field costs but not transport costs from the North to the South. The field development costs could range from LC conditions upwards, depending on whether the fields are located onshore or offshore.

Figure 6.42 shows the effects of the complex Alaskan fiscal system in money-of-the-day terms. The system is seen to be highly regressive with respect to both oil price and development cost changes. The take under LC conditions is generally around 70 per cent with rising real prices and nearly 72 per cent with falling real prices. The heavy reliance on imposts based on gross revenues (royalties and production tax) is the main explanation of the results. The overall level of take at MC levels of development cost becomes noticeably high, and with falling real prices the burden on investors has already become intolerable.

The share of economic rents accruing to the state and federal governments through the fiscal system at a 10 per cent discount rate is shown in Figure 6.43. It is seen that at LC conditions the government take varies from over 70 per cent with rising real prices to levels exceeding 90 per cent at falling real prices. The heavy reliance on production-based levies causes the large variation over the set of prices. The fiscal system is very regressive in discounted terms and becomes intolerable to investors at MC on all fields.

At a 5 per cent discount rate, government takes under the rising real price at LC conditions are in the 66 to 68 per cent range across the different field sizes; with falling real prices the range is from 74 per cent to 80 per cent. Takes exceed 100 per cent of rents at MC conditions on all fields. At a 15 per cent discount rate government take exceeds the economic rents under LC conditions in some fields. Government take escalates rapidly as discount rates are increased under the Alaskan system because of the heavy use of production-based levies. These commence with first production and their weight increases with the interest rate employed.

Under the scenario of collapsed oil prices, the tax take at 10 per cent discount rate exceeds 100 per cent of the economic rents under LC conditions on all fields. This is also the case for the 5 per cent discount rate. At zero real rate (5 per cent in money-of-the-day terms) the take varies between 89 per cent and 99 per cent on the fields depicted in the charts. In money-of-the-day terms the take is in the 75 to 84 per cent range across different fields. Pre-tax returns are very low under the collapsed-price scenario (see Figure 6.41), but the structure of the fiscal system is clearly insufficiently sensitive in its reaction to the price movements which have taken place recently to ensure that distortions to investment do not emerge. The heavy reliance on production-based levies is the root of the problem. When the level of tax is also very "high," the dangers of distortions evolving are, of course, increased. This system is not at all well related to economic rents. Of all the conventional instruments, production taxes are furthest removed from this target.

The Alaskan government claims a much greater share of the economic rents compared with the federal one. Under the scenario of constant real oil prices expected in 1985, under LC conditions at a 10 per cent discount rate the state government would take as much as 65 per cent of the rent on the VHV field, as opposed to 18 per cent by the federal government; on the MV field the state government would take 58 per cent, compared with 20 per cent by the federal government. The state government's share is boosted by the discounting process, because it obtains the royalty and production tax. At higher cost levels the state government's share is greater – the lower profitability of the projects reduces the federal income tax to a greater extent than it reduces production-based levies. The federal government's share is also reduced by the front-end relief available to an ongoing investor. In money-of-the-day terms the state government's share of net revenues on the VHV field drops to 46.1 per cent while the federal share increases to 18.8 per cent; on the MV field the shares are 46.9 per cent and 18.4 per cent respectively.

The position of the explorationist in the north of Alaska is examined on the basis of two sizes of exploration programs, a large one costing $100 million and a small one costing $20 million. The EMVs are shown in Tables 6.12 and 6.13.

Table 6.12 shows that the program costing $100 million produces positive EMVs under several chances of discovery and discount rates. On a post-tax basis the EMVs are positive only under optimistic

Table 6.12
Alaska (North)
Expected Monetary Values and Tax and Royalty Takes facing Explorationist, $100 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Tax and Royalty Take (%)
	Pre-Royalty and Tax	Post-Royalty and Tax	
Overall Discovery Rate: 1 in 2			
0	728.3	118.0	70.7
5	345.3	50.7	82.6
10	127.2	-23.4	121.1
15	-3.5	-68.6	-
Overall Discovery Rate: 1 in 5			
0	231.3	16.8	77.7
5	75.1	-13.5	125.3
10	-15.3	-46.1	-
15	-70.9	-66.9	-
Overall Discovery Rate: 1 in 10			
0	65.7	-16.9	111.9
5	-15.0	-34.8	-
10	-62.8	-53.6	-
15	-93.3	-66.3	-
Overall Discovery Rate: 1 in 20			
0	-17.2	-33.8	-
5	-60.1	-45.5	-
10	-86.5	-57.4	-
15	-104.6	-66.1	-

Table 6.13
Alaska (North)
Expected Monetary Values and Tax and Royalty Takes facing Explorationist, $20 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Tax and Royalty Take (%)
	Pre-Royalty and Tax	Post-Royalty and Tax	
Overall Discovery Rate: 1 in 2			
0	808.3	219.4	68.2
5	429.4	96.6	74.3
10	215.5	26.5	86.8
15	89.2	-14.9	115.4
Overall Discovery Rate: 1 in 5			
0	311.3	81.7	69.0
5	159.1	31.9	76.8
10	72.9	3.2	95.1
15	21.8	-13.9	155.9
Overall Discovery Rate: 1 in 10			
0	145.7	35.8	70.6
5	69.1	10.3	82.3
10	25.4	-4.5	120.1
15	-0.7	-13.5	1712.6
Overall Discovery Rate: 1 in 20			
0	62.8	12.8	74.8
5	24.0	-0.5	102.5
10	1.7	-8.4	5952.4
15	-11.9	-13.3	-

chances of discovery and low discount rates. The regressive nature and high level of the fiscal system are seen to reduce incentives to explore. There are risk-sharing advantages to being in an ongoing situation, and these become apparent when the situation of very poor prospectivity is examined. The two governments then share considerably in the exploration risks.

It was thought useful, if only for purposes of inter-country comparisons, to examine the consequences of a less costly exploration program costing $20 million. (It is recognized that this is very optimistic and could not apply to offshore locations.) Table 6.13 shows that pre-tax EMVs are generally positive except at high discount rates. While incentives to explore are reduced by the fiscal system, it is noteworthy that post-tax EMVs are positive in several of the scenarios. With a 1 in 5 chance of discovery and a 10 per cent discount rate, the post-tax and royalty EMV is $3.2 million. This indicates the size of bid that an investor would be prepared to make for a lease under these circumstances. If the fruit of the exploration were the discovery of the VHV/LC field, the investor would expect to make a net present value from developing the field of over $560 million; he would then receive a considerable share of the *ex post* economic rents. On the other hand, if the fruits of the exploration were the discovery of the MV/MC field, the net present value from developing the field would be -$420 million.

Under the collapsed-price scenario, pre-tax EMVs for a program of $100 million are negative under all scenarios examined. Under the very optimistic $20 million program there are positive EMVs under favourable geological prospectivity; they are negative for success rates of 1 in 10 and worse, and with the 1 in 5 chance of success positive values require a discount factor as low as 5 per cent. Post-tax EMVs are negative.

The situation is rather different in the south of Alaska, where wellhead values are much higher. Government share of economic rents at a 10 per cent discount rate under the oil price scenarios of 1985 are shown in Figure 6.44. It is seen that the takes are considerably lower than in the situation in the North. Under MC conditions government take is less than 100 per cent of the rents except under the scenario of falling oil prices. The explanation is the fall in the burden of production-based levies at the higher level of oil prices.

A further effect of the higher wellhead values in the South is the change in the distribution of revenues between state and federal government. Under the constant real world oil price of $27, the distribution of the share of economic rents collected is shown in Figure 6.45. The federal government's share is greater than under the lower price in the north of Alaska, reflecting the lower burden of production-based levies at the higher price levels.

Under the collapsed-price scenario, total government takes under LC conditions at the 10 per cent discount rate range from 73 to 78 per cent across the different field sizes. Under MC conditions they exceed 100 per cent. Under 15 per cent discount rates takes in the LC situations range from 80 to 92 per cent across the field sizes. Thus, while investment incentives are much reduced by the fiscal system, opportunities remain under favourable cost conditions.

As far as the explorationist engaging in a $60 million program is concerned, under the 1985 perspective with a $27 real oil price, pre-tax EMVs were generally positive. After tax EMVs were positive at the 1 in 5 chance of discovery up to discount rates of 15 per cent. With a 1 in 10 chance of success they remained positive up to discount rates of 10 per cent. With chances of discovery of only 1 in 20 post-tax EMVs became negative at all positive real discount rates. With an exploration program of $20 million, pre-tax EMVs under all scenarios were healthily positive; after tax the EMVs remained positive except under very low discovery rates and high discount rates.

Under the scenario of collapsed oil prices, an exploration program of $60 million resulted in negative pre-tax EMVs being produced in six of the scenarios considered; after tax, negative values were produced in nine of the scenarios. With a $20 million program pre-tax EMVs were positive under all scenarios except the unfavourable case of a 1 in 20 chance of discovery and a 15 per cent discount rate; after tax there were six cases of negative EMVs produced. Even under the collapsed price substantial economic rents can be earned in South Alaska. For example, with a 1 in 5 chance of discovery and 10 per cent real discount rate, the post-tax EMV under the $20 million exploration program is $9.2 million. If the explorationist discovered the HV/LC field, the net present value from its exploitation could exceed $400 million. On the other hand, if the LV/MC field were the fruit of the exploration, the net present value from its exploitation would be -$118 million. As in other jurisdictions employing the bidding system, the accuracy of the system in Alaska depends in part on how efficiently the bidding element operates.

The other elements in the fiscal package in Alaska are not directly linked to economic rents. The royalty and production tax elements in particular are unrelated to rents. The very large fields expected in Alaska mean that the cruder form of taxes can to some extent be absorbed without great economic distortions emerging. Given the high degree of oil price variation which has been experienced – and may continue in future – the system is clearly not sufficiently sensitive to prevent investment disincentives from emerging on higher cost fields. The high average rate of tax combined with the structural features noted above increases the chances of distortions emerging.

Figure 6.40
Alaska (North)
Real Net Present Values, 10% Real Discount Rate (no taxes)
Constant Real Oil Price ($27)

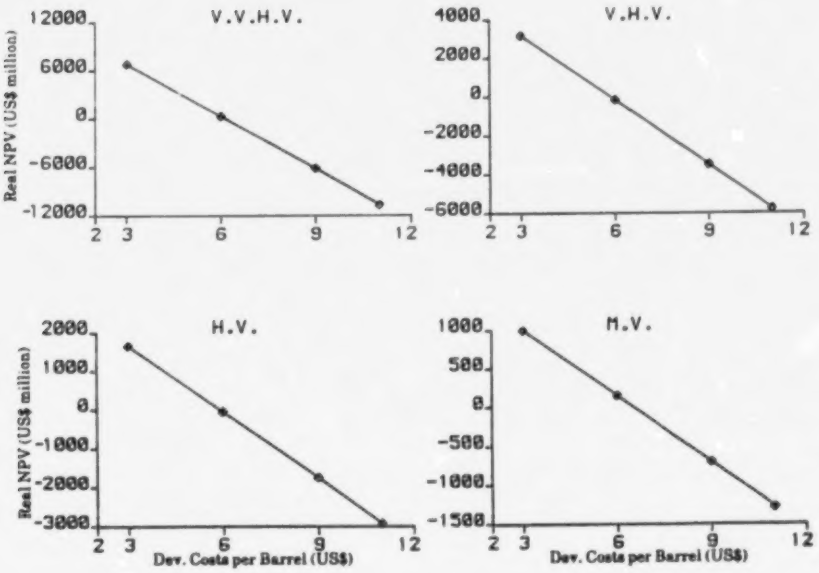


Figure 6.41
Alaska (North)
Real Net Present Values, 10% Real Discount Rate (no taxes)
Collapsed Real Oil Price

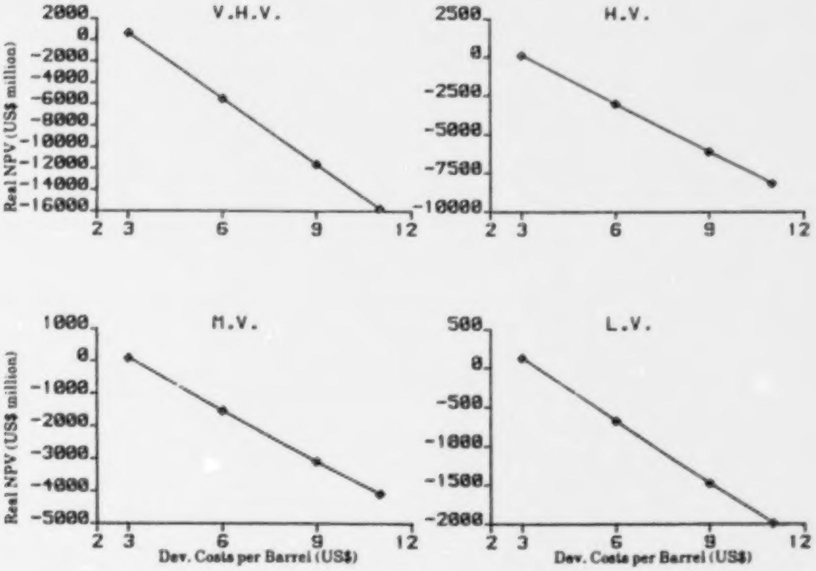


Figure 6.42
Alaska (North)
Nominal Government Take (as percentage of resources generated)
1985 Price Perspectives

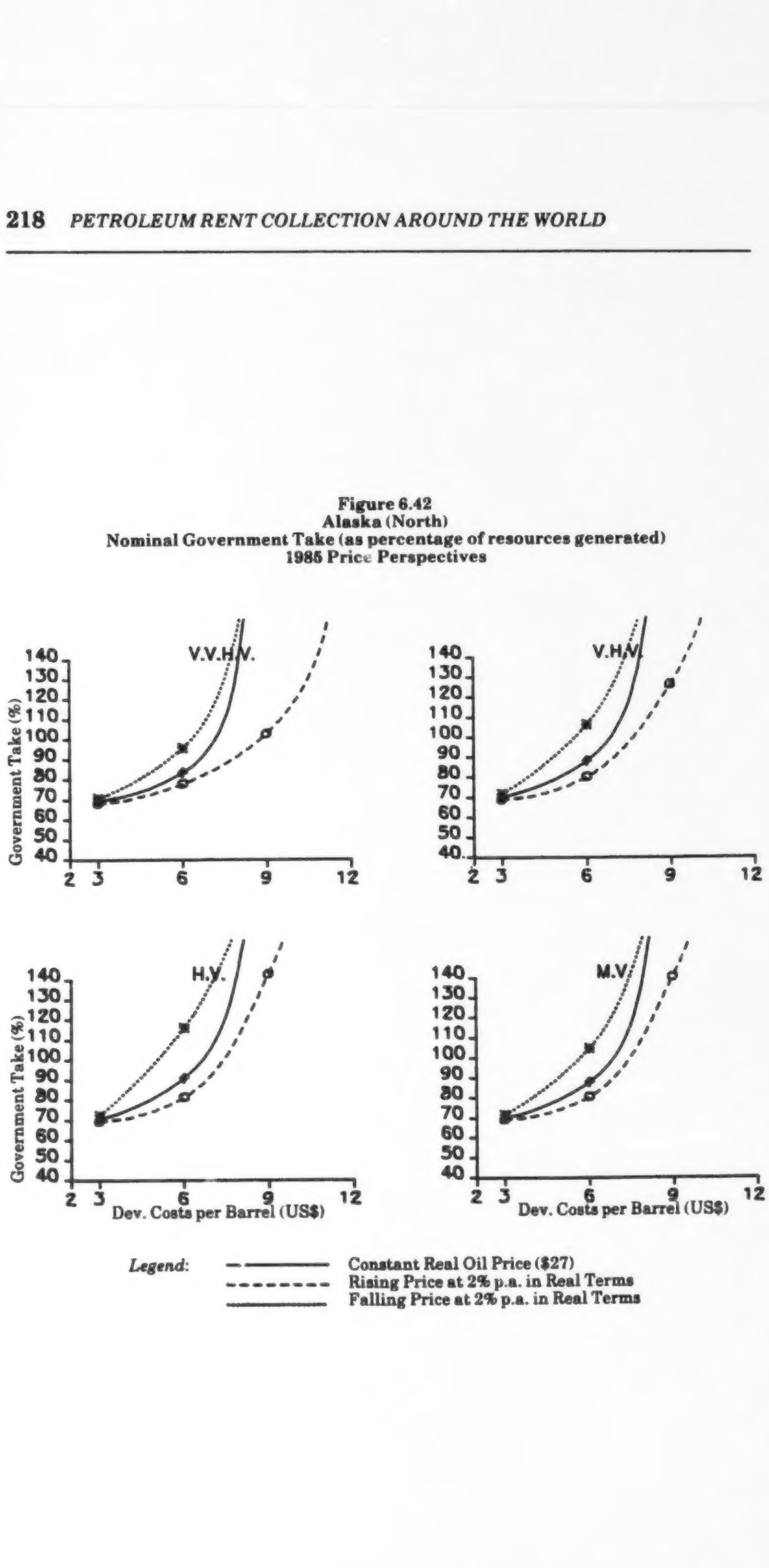


Figure 6.43
Alaska (North)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

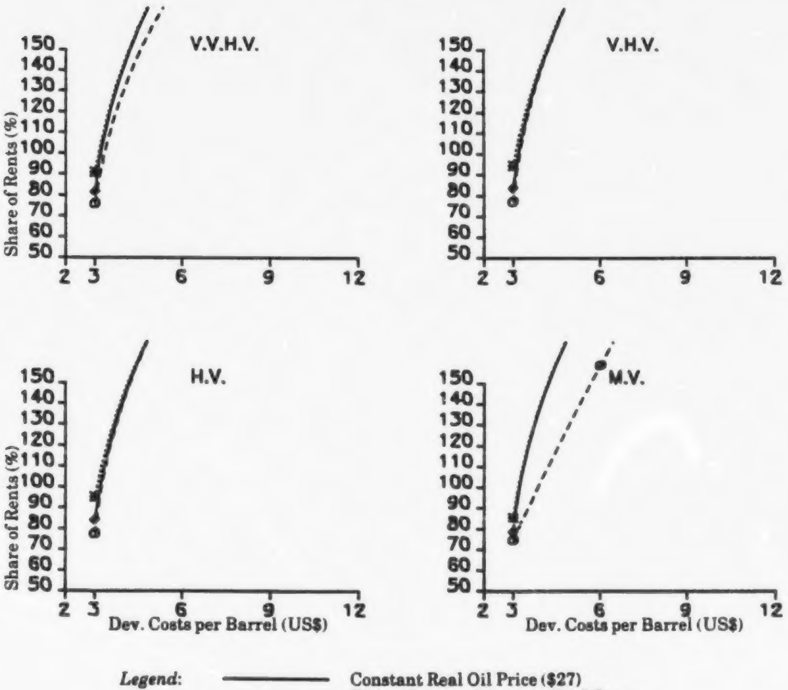


Figure 6.44
Alaska (South)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

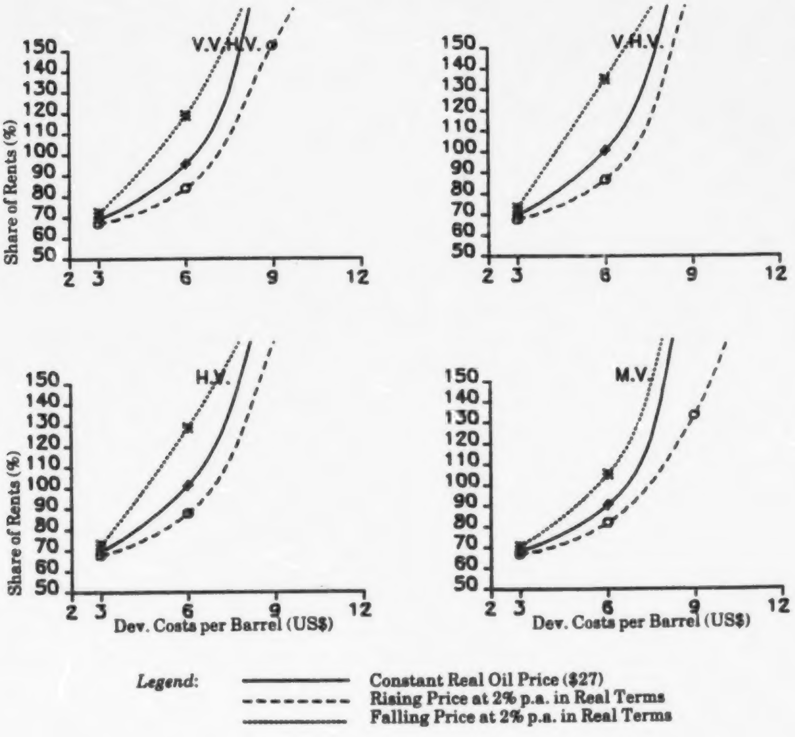
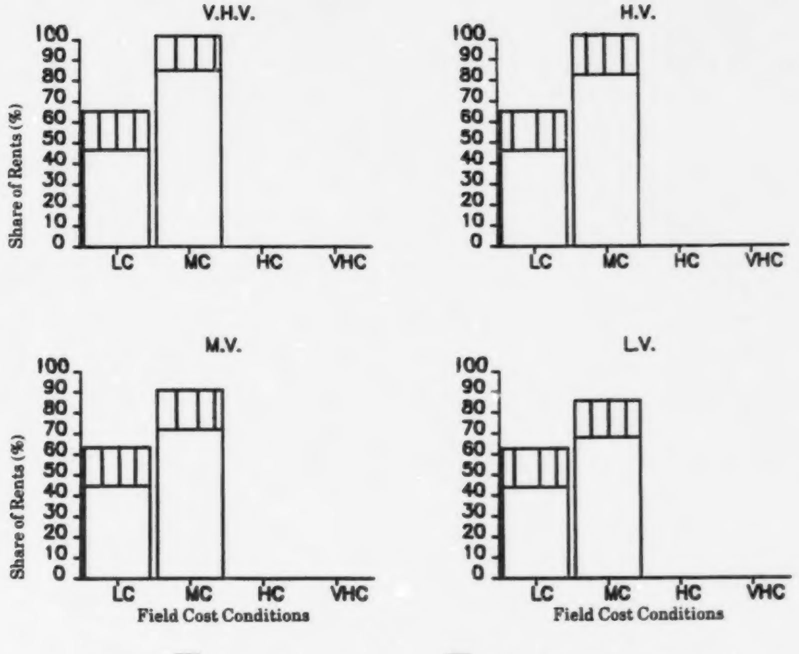


Figure 6.45
Alaska (South)
Distribution of Economic Rents, 10% Real Discount Rate
Constant Real Oil Price ($27)



Texas

As was discussed in Chapter 3, typical fields in Texas are very much smaller than those in offshore situations. The pre-tax net present values at 10 per cent for two typical fields, "prolific" and "modest," over a range of development costs are shown in Figure 6.46 and 6.47 for a 1985 oil price perspective and the collapsed-price scenario, respectively.

The share of economic rents taken in taxes by government at the 10 per cent discount rates under the 1985 oil price scenarios is shown in Figure 6.48, along with the share received jointly by governments and the (private) landlord in the form of royalties. The share accruing to governments only is seen to be around 35 per cent on the "prolific" field and 33 to 36 per cent on the "modest" one. The system is proportional/very mildly progressive. The production tax imposed by the Texas government is relatively small, at 4.6 per cent, and its regressive impact is outweighed by the beneficial effects of the investor's being in an ongoing position. The property tax is a share of net present value and by definition proportional in discounted terms. The front-end relief for drilling expenditure causes the income tax system to be mildly progressive in money-of-the-day terms as costs increase: the value of these benefits increases with the level of expenditure in relation to a given income stream. The yield of the Windfall Profits Tax is very small on new fields but it does increase with oil prices. The overall consequences are that the tax system tends to be progressive in money-of-the-day terms on the 1985 oil price scenarios. When the landlord's royalty is added, the system becomes regressive in discounted terms. The total level of take increases sharply but is still below 100 per cent under all the cost conditions examined.

At the 15 per cent discount rate (Figure 6.49) government take remains proportional/mildly progressive, with the level being slightly higher than that attained under the 10 per cent rate. The production tax is responsible for this outcome. The loss of the investment tax credit has helped to make the system produce a slightly higher take at higher discount rates. The total take, including the landlord's share, goes up more noticeably with the discount rate, because the burden of the royalty increases with the rate of interest employed.

Figure 6.50 illustrates the allocation of the shares accruing to landlord, federal government, and Texas government with a 10 and a 15 per cent discount rate, under the 1985 oil price scenario. The property tax, which accrues to local governments, is included in the state government's share, and account is taken of the property tax payable by the landlord. The federal government's share is the largest on the "prolific" field but on the "modest" one the landlord's share is generally the largest. At lower discount rates the federal government's share would increase relative to that of the landlord and the Texas government. With a 15 per cent discount rate the shares of the state and local governments and the landlord increase, especially in the less profitable "modest" field. This reflects the higher burden of production-related imposts under situations of reduced profitability.

The position under the scenario of collapsed oil prices with a 10 per cent discount rate is shown in Figure 6.51, which indicates both the government tax take on its own and the joint government-landlord take from taxes and royalty. The system is seen to be regressive, with the level of take higher than under the 1985 oil price expectations. This is primarily due to the production tax and royalty. The levels are still lower than in many other petroleum-producing provinces, however. At a 15 per cent discount rate the total takes remain comparatively low on the "prolific" field, ranging from 55.4 per cent for the lowest cost to 62 per cent for the highest cost considered; on the "modest" field, however, the take becomes 76 per cent under LC conditions, 108 per cent at MC, and 330 per cent at HC. Thus, investment disincentives can be produced by the tax system under this oil price scenario.

In Texas there are many fields smaller than those that have been considered in this analysis, and their unit costs are considerably higher. Under the collapsed-price scenario very many of these became uneconomic on a post-tax basis at the discount rates considered here.

To examine the position of the explorationist in Texas, a program of $1 million under the oil price expectations of 1985 was considered. The results are shown in Table 6.14. It is seen that pre-tax and royalty EMVs are positive in all but two cases, while after tax and royalty there are four cases where the EMVs become negative. Under a $5 million program the EMVs before tax and royalty are negative in the majority of cases considered and after tax and royalty in all cases. Only with a chance of discovery of 1 in 2 do the post-tax and royalty EMVs remain positive under the $5 million program.

The position under the collapsed oil price for a $1 million program is summarized in Table 6.15. Before tax and royalty, EMVs are negative in six cases considered; after tax and royalty, EMVs become negative under eight of the cases examined. The fiscal system obviously has an adverse effect on exploration incentives. With a program costing $5 million the EMVs are generally negative in both pre-tax and post-tax terms. If smaller fields had been included in the analysis, the incentives to explore in Texas would have been shown to be considerably less.

Under the collapsed oil price, with a 1 in 5 chance of making a discovery from a $1 million program and with a 10 per cent discount rate, the investor would have an EMV of $0.1 million. If he discovered the "prolific" field under LC conditions, the net present value from its development would exceed $8 million. On the other hand, if he discovered the "modest" field under HC conditions, the net present value from its development would be -$0.2 million.

Table 6.14
Texas
Expected Monetary Values and Government and Royalty Takes facing Explorationist, $1 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Tax and Royalty Take (%)
	Pre-Royalty and Tax	Post-Royalty and Tax	
Overall Discovery Rate: 1 in 5			
0	4.9	2.1	56.4
5	3.3	1.4	58.6
10	2.2	0.8	62.7
15	1.4	0.4	70.4
Overall Discovery Rate: 1 in 10			
0	1.9	0.8	60.2
5	1.1	0.4	67.3
10	0.6	0.1	86.7
15	0.1	-0.2	206.7
Overall Discovery Rate: 1 in 20			
0	0.5	0.1	79.7
5	0.0	-0.1	435.1
10	-0.3	-0.3	-
15	-0.5	-0.4	-

In sum, the fiscal system applied to petroleum exploitation in Texas was unlikely to have caused economic inefficiencies under 198 oil price expectations. With collapsed oil prices, however, exploration incentives and new field developments could both be impaired. The tax system as a whole is not directly targeted on economic rents. Even though nominal tax rates are not very high, the existence of many marginal field situations means that distortions can be produced. The main cause of the slump in activity in 1986 is clearly the fall in oil prices; investment incentives are frequently inadequate on a pre-tax basis.

Table 6.15
Texas
Expected Monetary Values and Government and Royalty Takes facing Explorationist, $1 Million Program
Collapsed Real Oil Price

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Tax and Royalty Take (%)
	Pre-Royalty and Tax	Post-Royalty and Tax	
Overall Discovery Rate: 1 in 5			
0	2.4	0.9	61.6
5	1.4	0.4	69.3
10	0.7	0.1	89.0
15	0.2	-0.2	190.0
Overall Discovery Rate: 1 in 10			
0	0.7	0.2	76.3
5	0.2	-0.1	161.0
10	-0.2	-0.3	-
15	-0.5	-0.5	-
Overall Discovery Rate: 1 in 20			
0	-0.1	-0.2	-
5	-0.4	-0.4	-
10	-0.6	-0.5	-
15	-0.8	-0.6	-

Figure 6.46
Texas
Real Net Present Values, 10% Real Discount Rate (no taxes)
Constant Real Oil Price ($27)

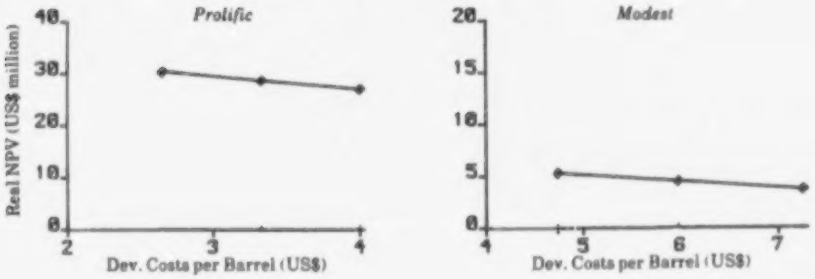


Figure 6.47
Texas
Real Net Present Values, 10% Real Discount Rate (no taxes)
Collapsed Real Oil Price

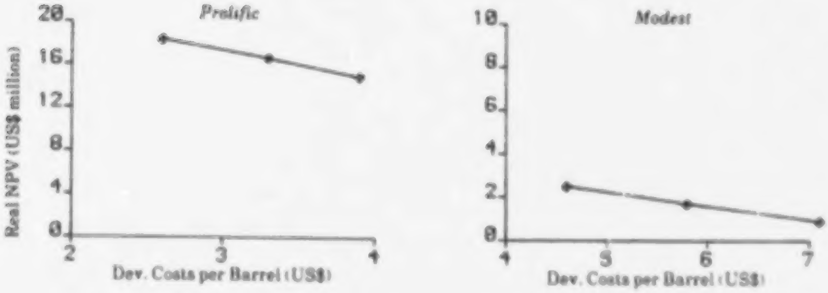
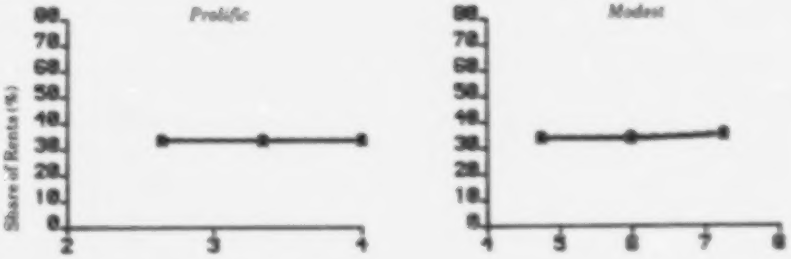


Figure 6.48
Texas
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

A. Government Share



B. Government and Landlord Share

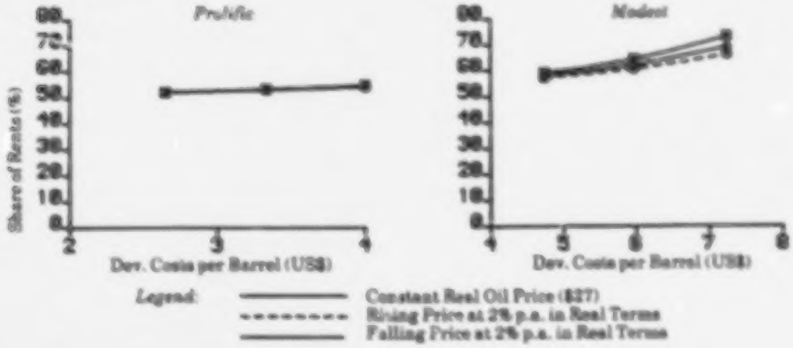
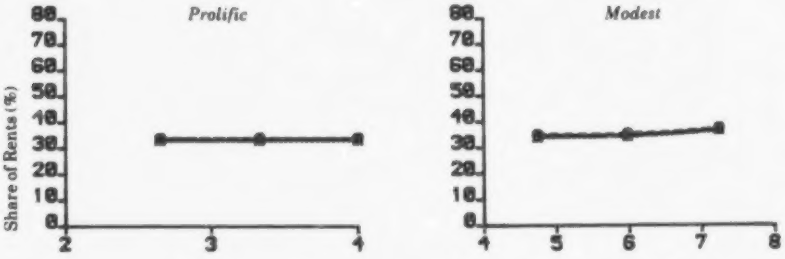


Figure 6.49
Texas
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

A. Government Share



B. Government and Landlord Share

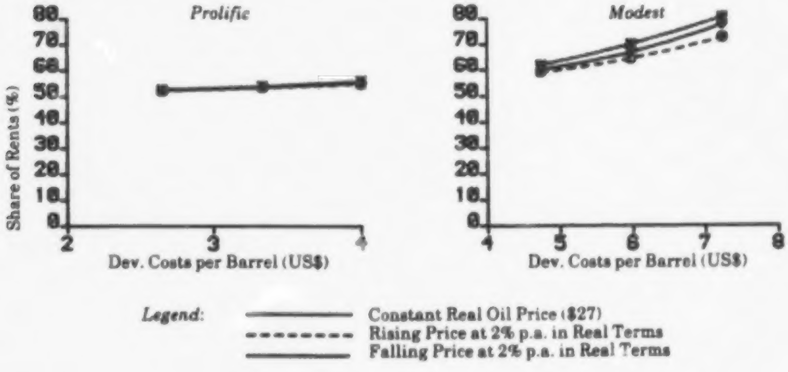
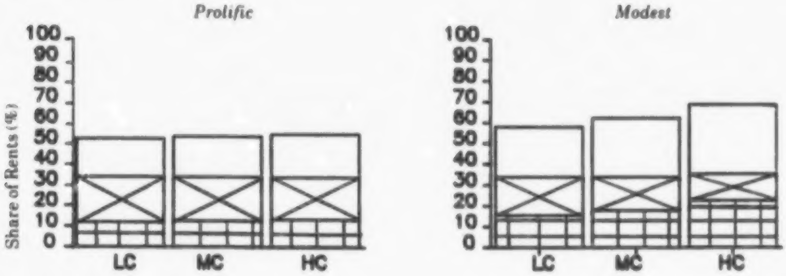


Figure 6.50
Texas
Distribution of Economic Rents, 10% and 15% Real Discount Rates
Constant Real Oil Price ($27)

A. 10% Real Discount Rate



B. 15% Real Discount Rate

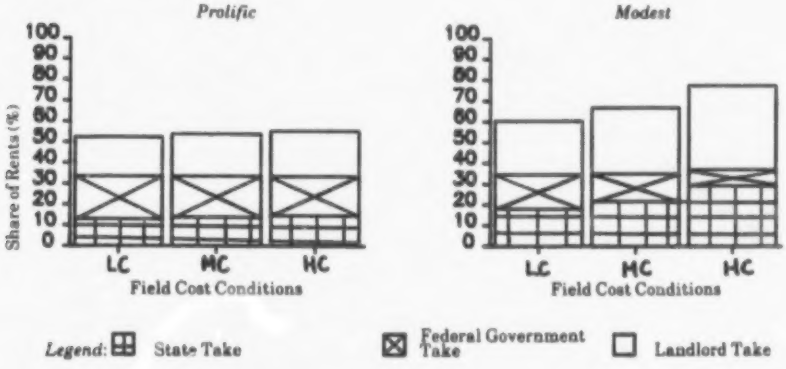
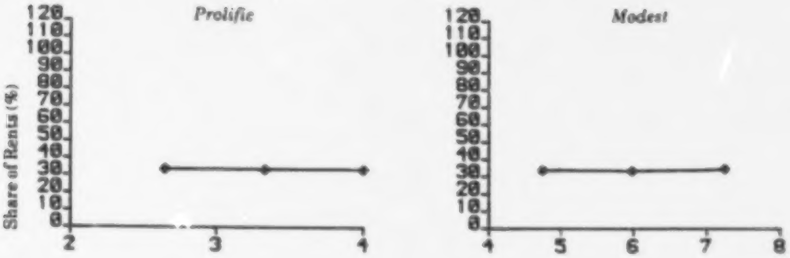
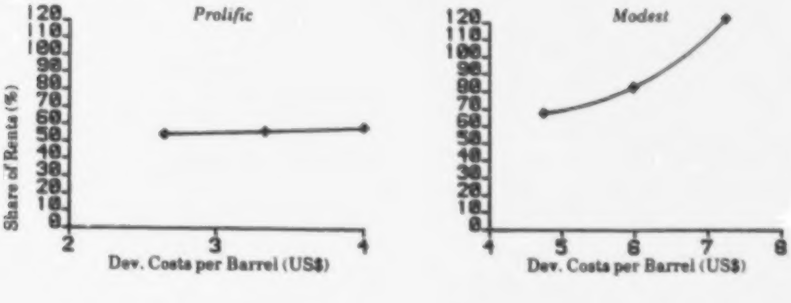


Figure 6.51
Texas
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price

A. Government Share



B. Government and Landlord Share



(10) Canada

Alberta

The net present values to investors before tax and royalty on the HV and LV fields in Alberta at 10 per cent real discount rates are shown in Figures 6.52 and 6.53. Figure 6.52 is based on the 1985 oil price perspectives and Figure 6.53 on the collapsed oil price. In both cases a distinction is made between the pre-NEP prices obtainable by producers and the NEP and post-NEP price levels. The pre-NEP system analyzed is that immediately prior to the introduction of the NEP; for the NEP system the latest version has been examined. The results for the LLV (very low volume) field are not shown, as this project was very frequently non-viable: under the 1985 price perspective net present values on the LLV field were positive at a 5 per cent discount rate under the LC situation only; at higher costs and discount rates returns were negative.

(a) Pre-NEP System

In order to analyze the fiscal system as it operated before the introduction of the NEP, the shares of economic rents accruing to the various recipients are considered first in terms of world prices, with the share of crude-oil consumers being included in the calculation. Figure 6.54 illustrates the distribution of the rents among the federal government, Alberta government, and oil producers resulting from the operation of the royalty and tax system under 1985 oil pricing expectations at a 10 per cent rate of discount. Rents remaining are split between the Alberta government and the investor – the mineral rights are allocated by means of bonus bids, the revenues from which accrue to the Alberta government as the owner of the resource. The distribution of the remainder rents depends upon how efficiently the bidding system operates.

From Figure 6.54 it is seen that the Alberta government obtains a higher share of the rents under the fiscal system than does the federal government. The royalty system is progressively related to production and this raises Alberta's share of the rents on the HV field. The provincial government share, being dominated by the royalty, is also seen to increase on each field as exploitation costs increase.

A fuller picture of the governments' share of economic rents is seen in Figure 6.55. The higher share of the rents going to governments on the larger field is clearly discernible. The fiscal system is seen to be regressive with respect to cost changes. Under the range of cost conditions that are most likely in Alberta, the system is only mildly regressive; but as less profitable field situations are encountered, the system becomes distinctly more regressive in character. The royalty obviously plays the key role here. The system would have been more regressive were it not for the front-end reliefs in the income-tax system for ongoing investors in new field developments, and, most importantly, were it not for the royalty tax rebates and credits.

The fiscal system interacts with oil price movements in an unusual way. In money-of-the-day terms and at zero discount rates, the takes are marginally regressive in relation to oil price changes. This is explained by the increased burden of the royalty at lower levels of oil prices. At higher discount rates the front-end reliefs for income tax to ongoing investors plus the royalty tax credit and rebate become relatively more important the lower the level of oil prices. Under the most likely cost conditions these reliefs combine to make the system progressive with respect to oil prices. At higher cost levels, however, these reliefs are insufficiently strong to prevent the take from increasing to a greater extent under the scenarios of lower prices. The royalty formula inherently produces this effect when operating in isolation.

There is another influence at work, however, namely, the increased real burden of royalties as the discount rate increases. This effect tends to push up the take the lower the price level. There are thus opposing forces at work. It is seen from Figure 6.55 that the structure of government take is generally more regressive with a higher discount rate. The level of take, too, is higher, especially on the LV field, reflecting in particular the net increase in the burden of royalty payments. At 20 per cent discount rates the ranking of the takes remains unchanged.

A remarkable feature of the results in their international context is the comparative stability of the fiscal takes in relation to oil price movements. In other countries the spread of take for the same oil price movements is much greater. In Alberta the spread is limited through the compensating movements in the factors determining the effective royalty burden.

The above analysis has considered governments' shares of economic rents in terms of world prices. From the viewpoint of investors, however, government takes have their influence when measured at the prices received by producers. The possibilities of distortions to investment decisions are best measured by examining the takes at the domestic prices received by investors. In Figure 6.56 the governments' shares as measured on this basis are shown at 10 per cent and 15 per cent discount rates. The takes are all distinctly higher than when measured at free-market prices, but they are still below 100 per cent on all price scenarios and so cause no distortions to investment in these fields. The margin is now quite small on the highest cost situations, however.

At the lower levels of oil prices it is seen that the spread of government takes under the different oil price scenarios remains quite small. The system becomes more regressive in relation to oil prices at high cost levels. The royalty tax credit, royalty rebate, and income-tax allowances are insufficiently strong to prevent the royalty formula from operating to make the take highest at the lowest oil price level when costs become very high.

Government take under the collapsed-price scenario is shown in Figure 6.57. The working of the system is shown at controlled prices to isolate any distorting effects on investment. The shares of government are seen to be similar to what they were under the 1985 price scenarios for the most likely cost conditions. The main explanation for this rather surprising finding is that the royalty burden does not increase as much as would occur under a normal royalty system; the royalty tax credit and royalty rebates give powerful relief. At very high levels of cost, government take approaches 100 per cent of the rents on the HV field and can actually exceed this figure on the LV field, especially with a higher discount rate. Fields which are just acceptable on a pre-tax basis become unacceptable after royalty and tax.

The position of the explorationist is now examined. The effects of the fiscal system on the investor under the 1985 oil price scenario are summarized in Table 6.16 for programs of $1 million and $5 million. Pre-tax EMVs are generally positive apart from the 1 in 20 chance of success at a 15 per cent discount rate. Post-tax values remain positive under the $1 million program. With the $5 million program EMVs become negative at the 15 per cent discount rate under the 1 in 10 chance of success and at 10 per cent discount rate with a 1 in 20 chance. Tax takes generally are only mildly regressive in their impact. The moderate level of tax, reflecting the combined effects of the large number of allowances, is the most important factor in the maintenance of reasonably good exploration incentives. A program costing $10 million would have negative pre-tax EMVs at the 1 in 20 chance of discovery; on a post-tax basis EMVs turn negative at the 10 per cent discount rate under the 1 in 10 chance of discovery and at the 15 per cent discount rate under the 1 in 5 chance.

Under the collapsed oil price the situation is summarized in Table 6.17. It is seen that pre-tax EMVs are positive for a $1 million program, but three negative outcomes emanate from a $5 million one. Post-tax values remain positive for the $1 million program, while the $5 million program results in six cases of negative EMVs. At the 1 in 20 chance of success there is no positive post-tax EMV when interest rates exceed 0 per cent, and at the 1 in 10 chance of success the venture is unattractive at a 10 per cent discount rate; with a 1 in 5 chance the EMV becomes negative at the 15 per cent discount rate. With a program costing $10 million, the fiscal system produces even more disincentive effects.

Table 6.16
Alberta (Pre-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $1 Million and $5 Million Program, Constant Real Oil Price ($27)

Real Discount Rate (%)	$1 Million Program			$5 Million Program		
	Expected Monetary Values (US$ million, 1986)		Government Take (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax		Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5						
0	66.9	22.9	63.2	62.9	20.7	64.2
5	39.4	12.8	63.9	35.2	10.5	65.9
10	25.6	7.9	64.3	21.2	5.5	67.7
15	17.7	5.1	64.7	13.1	2.7	70.4
Overall Discovery Rate: 1 in 10						
0	33.0	11.2	63.4	29.0	9.0	65.7
5	19.2	6.1	64.3	15.0	3.8	69.3
10	12.2	3.6	65.0	7.8	1.2	74.7
15	8.3	2.3	65.9	3.6	-0.2	
Overall Discovery Rate: 1 in 20						
0	16.0	5.3	63.9	12.0	3.2	69.6
5	9.1	2.8	65.3	4.9	0.4	81.1
10	5.6	1.5	66.8	1.2	-0.9	122.8
15	3.6	0.8	68.7	-1.1	-1.7	

Table 6.17
Alberta (Pre-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $1 Million and $5 Million Program, Collapsed Real Oil Price

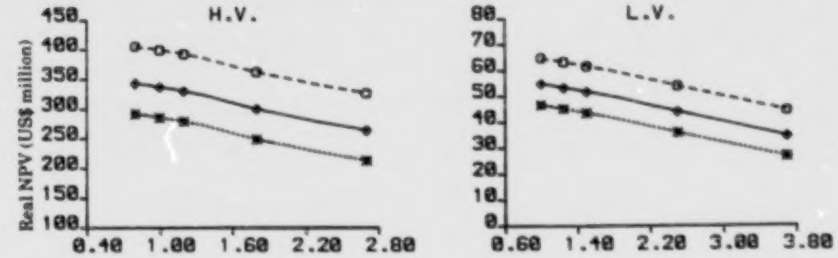
Real Discount Rate (%)	$1 Million Program			$5 Million Program		
	Expected Monetary Values (US$ million, 1986)		Government Take (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax		Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5						
0	40.6	14.0	62.8	36.6	11.8	64.6
5	23.5	7.6	63.7	19.3	5.3	67.3
10	14.9	4.5	64.5	10.5	2.1	71.5
15	10.0	2.7	65.6	5.3	-0.2	79.8
Overall Discovery Rate: 1 in 10						
0	19.8	6.7	63.2	15.8	4.6	67.4
5	11.2	3.5	64.5	7.0	1.2	74.4
10	6.9	1.9	65.9	2.5	-0.5	
15	4.4	1.0	67.9	-0.2	-1.5	
Overall Discovery Rate: 1 in 20						
0	9.4	3.1	64.1	5.4	0.9	76.5
5	5.1	1.5	66.2	0.9	-0.8	133.2
10	2.9	0.7	69.3	-1.5	-1.7	
15	1.6	0.2	74.5	-3.0	-2.3	

Bonus bidding is an integral part of the arrangements for collecting economic rents in Alberta. Under the 1985 expectation of a constant real oil price of $27, a bidder contemplating a $1 million exploration program who felt he had a 1 in 5 chance of making a discovery and who had a 10 per cent real rate of discount would have a post-tax EMV of $7.9 million. If he discovered the HV/MC field he would obtain a net present value of $107 million from its development; if, however, he discovered the LLV/MC field he would face a net present value of -$0.3 million. Under the collapsed oil price the post-tax EMV on the same assumptions becomes $4.5 million. The corresponding net present values from the HV/MC and LLV/MC fields become $64 million and -$0.5 million. The efficiency of the bidding system plays a major role in determining the accuracy of the rent-collecting mechanism.

In sum, the pre-NEP fiscal system in Alberta does not produce as many distortions as many other fiscal systems. This result is achieved by the maintenance of a level of take below that in many other jurisdictions. The complex royalty scheme in Alberta, with its set of associated reliefs, is more flexible to changes in the operating environment than are more conventional royalty mechanisms. The whole system is only indirectly related to the target of economic rents. Whether the whole system efficiently collects economic rents depends on how well the bidding system operates. The royalty and tax system can leave a significant share of the rents in the hands of investors under "high" price situations. It could also cause distortions to investment when profitability is quite low.

Figure 6.52
Alberta
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

A. Pre-NEP Prices



B. NEP/Post-NEP Prices

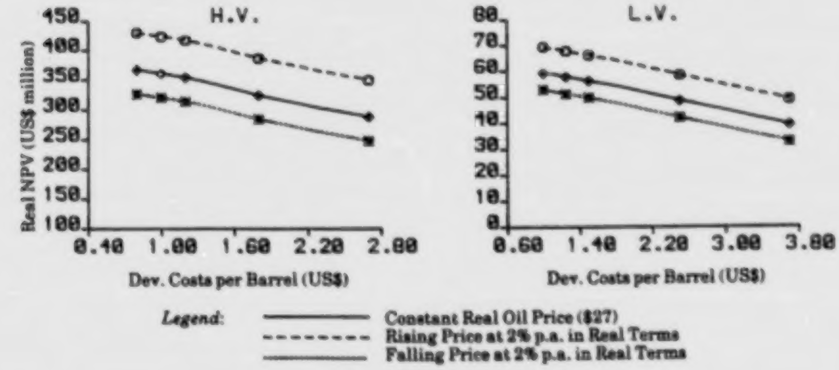
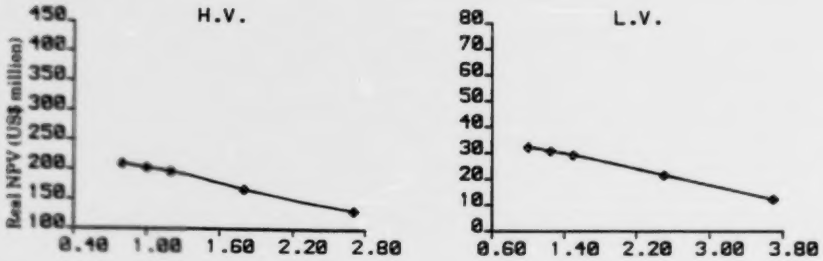


Figure 6.53
Alberta
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

A. Pre-NEP Prices



B. NEP/Post-NEP Prices

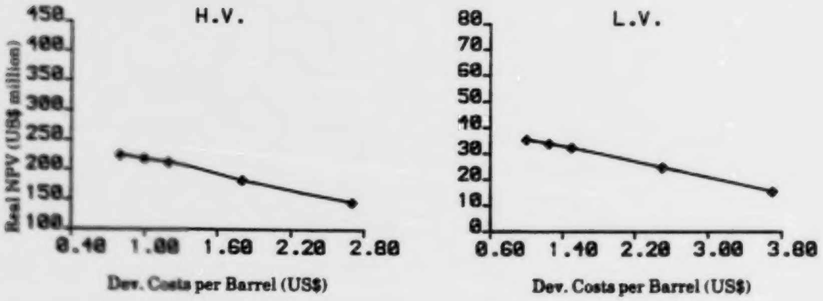
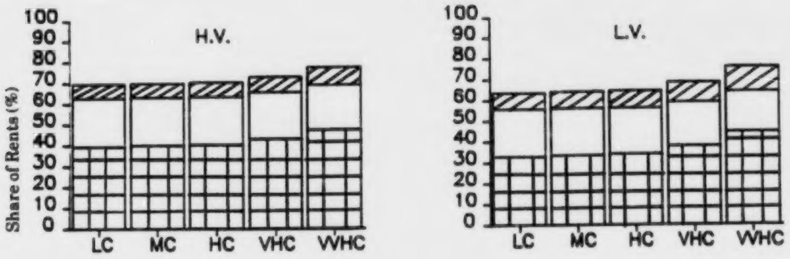


Figure 6.54
Alberta (Pre-NEP System)
Distribution of Economic Rents, 10% and 15% Real Discount Rates
Constant Real Oil Price ($27)

A. 10% Real Discount Rate



B. 15% Real Discount Rate

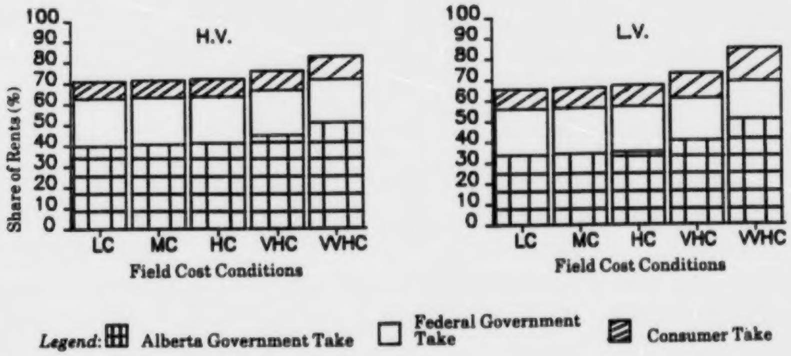
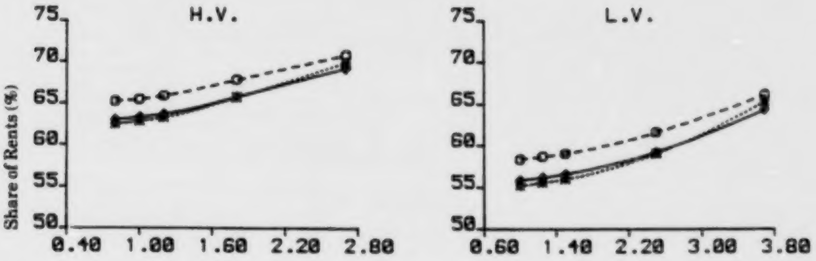
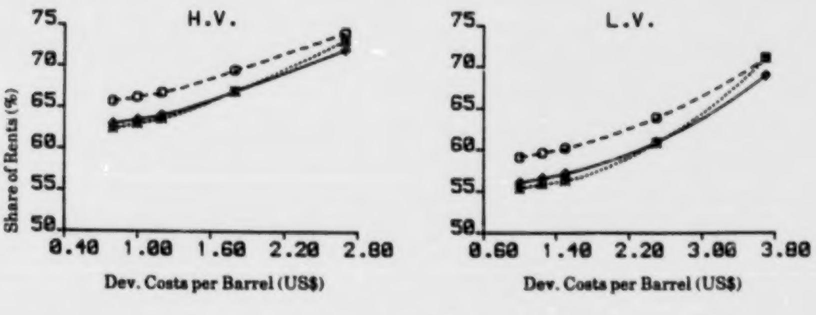


Figure 6.55
Alberta (Pre-NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates, World Prices
1985 Price Perspectives

A. 10% Real Discount Rate



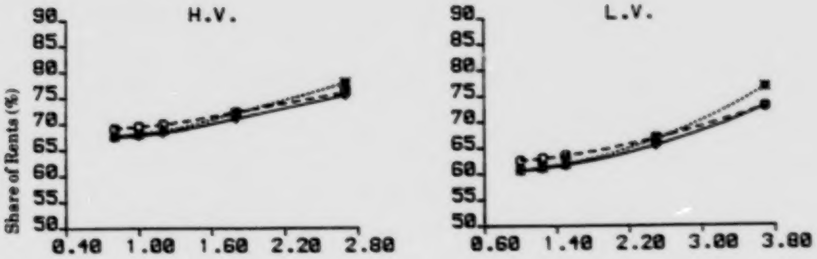
B. 15% Real Discount Rate



Legend: ——— Constant Real Oil Price ($27)
- - - - - - - Rising Price at 2% p.a. in Real Terms
·············· Falling Price at 2% p.a. in Real Terms

Figure 6.56
Alberta (Pre-NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates, Domestic Prices
1985 Price Perspectives

A. 10% Real Discount Rate



B. 15% Real Discount Rate

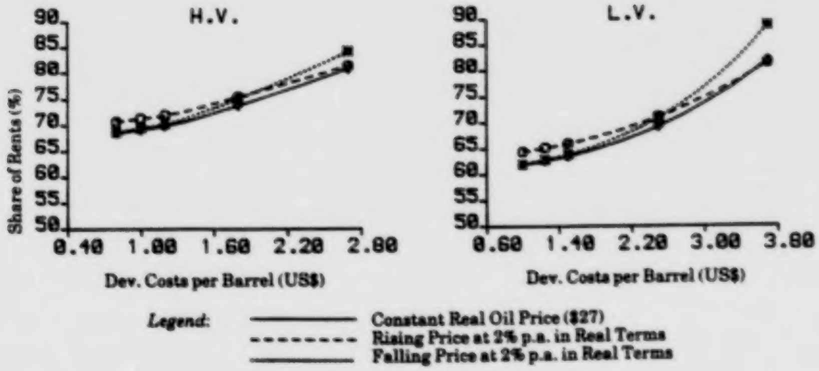
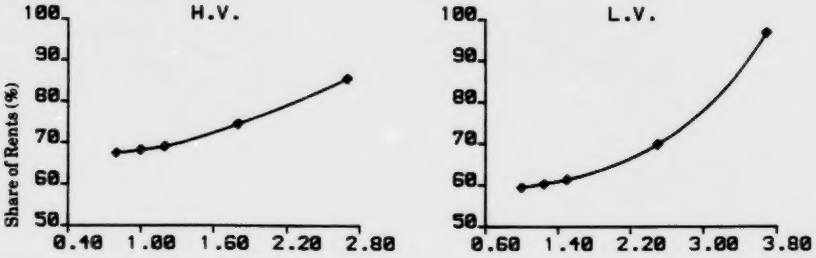
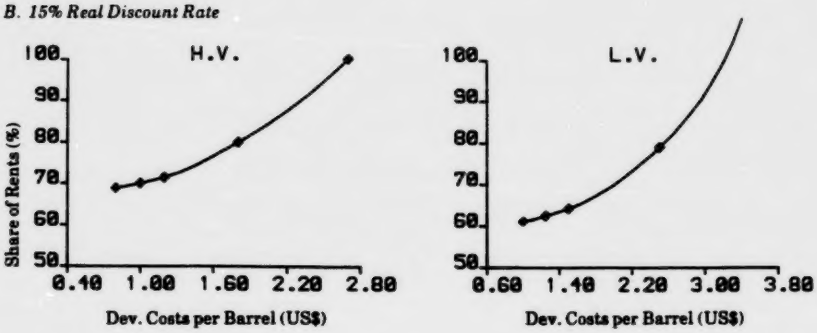


Figure 6.57
Alberta (Pre-NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates, Domestic Prices
Collapsed Real Oil Price

A. 10% Real Discount Rate



B. 15% Real Discount Rate



(b) NEP System

As was made clear earlier, there are several variants of the NEP. The version examined here is the system in operation in its latest days. Figures 6.58 and 6.59 show the shares of the economic rent accruing to governments under the NEP with the 1985 oil price perspectives at 10 per cent and 15 per cent discount rates. Figure 6.58 considers the case of maximum PIP grant (20 per cent of approved costs) and Figure 6.59 the minimum (no PIP grant). The systems are seen to produce takes at higher levels than under the pre-NEP scheme. The systems are also more regressive with respect to costs. The scheme excluding the PIP benefits is more severe, and investment disincentives can be introduced under high cost conditions. Both systems are more regressive in relation to oil price changes than the pre-NEP one was. The presence of the PGRT is an obvious influence here. On the other hand the "early" receipt of PIP benefits makes the NEP system less regressive in relation to both oil price and development cost changes.

Compared with other jurisdictions the spread of takes under the three 1985 oil price scenarios is still not remarkably high, as the compensating factors referred to in discussing the pre-NEP system still operate. Under the NEP scheme the PGRT by itself tends to make the tax takes spread out over the range of price scenarios, while the presence of PIP benefits helps to restrict this effect. At a 20 per cent rate of discount on the system excluding PIP benefits, government take on the HV field is in the 85 to 87 per cent range for the most likely cost conditions, but rises to 108 per cent under the very highest costs examined. At a 5 per cent discount rate it is in the 80 to 84 per cent range for the most likely costs but reaches 91 per cent at the highest cost level. In money-of-the-day terms the system is broadly proportional in both the HV and LV fields with respect to both oil price and cost changes for the most likely range of cost conditions. It becomes mildly regressive under very high costs. The takes are also fairly close together under the different price scenarios under the most likely cost levels. On the HV field, takes are 74 to 79 per cent on likely cost conditions and attain 83 per cent under very high costs; on the LV field the range is 64 to 68 per cent under likely cost conditions and 79 per cent under the highest costs.

The shares of the rents accruing to the federal and Alberta governments are shown in Figure 6.60. Compared with the pre-NEP system there is an increase in the shares of the rents going to governments as a whole, but the federal government shows a striking gain in relation to all other possible recipients.

The share of the rents collected by governments under the collapsed oil price is shown in Figures 6.61 and 6.62, again for maximum and minimum PIP grants, respectively. Takes do not change dramatically under the most likely cost conditions, but under high cost conditions they do reach levels which certainly produce investment disincentives. Nevertheless, and despite the introduction of the PGRT (which is not related to field profitability), the system on these relatively attractive fields does not introduce such obvious distortions as are evident in some other countries. The scheme is, of course, not directly related to the economic rents from petroleum exploitation. It is remarkably complex, and the danger of distortions to investment is reduced at the cost of an extremely elaborate system of allowances.

To consider the effects of the NEP system on exploration, programs of $1 million, $5 million and $10 million were examined under maximum and minimum PIP grants; for exploration activities the maximum PIP grant is 35 per cent of eligible expenditures. Under the 1985 oil price scenario, pre-tax and post-tax EMVs remained positive in all cases under the $1 million program. The position for a program of $5 million is summarized in Table 6.18, which shows that pre-tax EMVs are generally positive except at the lowest level of prospectivity and highest discount rate. Post-tax EMVs are negative in three cases where the maximum PIP is available and in six cases where the grants are not available. The fiscal system becomes severe in situations of low prospectivity and high discount rates. With a program of $10 million, pre-tax EMVs are negative in four of the scenarios examined; on a post-tax basis they are negative in six cases when maximum PIP is available and in nine cases when PIP is not available.

Under the collapsed-price scenario with the $1 million program, pre-tax EMVs are positive under all conditions. They are also positive on a post-tax basis when PIP is available at 35 per cent; when PIP is not available, the post-tax EMV becomes negative in one case. The position for a $5 million program is summarized in Table 6.19. It is seen that pre-tax EMVs are negative in two cases. On a post-tax basis they are negative in six cases where maximum PIP is available and in nine cases where no grant is available. In situations where exploration becomes only marginally attractive on a pre-tax basis, the fiscal system is seen to become very severe and can readily introduce disincentives on investors. Obviously, at higher levels of exploration expenditure the disincentive effects of the fiscal system become stronger – with a $10 million program post-tax EMVs are negative in all cases when PIP grants are not available and in nine cases when PIP is available at 35 per cent.

Overall, the NEP fiscal system is extremely complex and cumbersome. It contains a large number of imposts, some of which are not well related to the target of economic rents. The crudities of the royalty and PGRT systems are modified by the presence of a bewildering number of special allowances designed to mitigate the

Table 6.18
Alberta (NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $5 Million Program, Constant Real Oil Price ($27)

Real Discount Rate (%)	No PIP: Expected Monetary Values (US$ million, 1986)		No PIP: Government Take (%)	Maximum PIP (35%): Expected Monetary Values (US$ million, 1986)		Maximum PIP (35%): Government Take (%)
	Pre-Tax	Post-Tax		Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5						
0	65.7	12.7	80.7	65.7	14.5	78.7
5	37.5	5.5	85.2	37.5	7.3	81.8
10	23.2	2.1	90.9	23.2	3.9	85.1
15	14.8	-0.2	101.3	14.8	2.0	89.5
Overall Discovery Rate: 1 in 10						
0	30.3	5.0	83.5	30.3	6.4	79.9
5	16.1	1.3	91.9	16.1	2.7	84.5
10	8.8	-0.4	105.0	8.8	1.0	91.4
15	4.5	-1.4	132.0	4.5	-0.3	108.9
Overall Discovery Rate: 1 in 20						
0	12.7	1.2	90.9	12.7	2.3	82.8
5	5.4	-0.8	114.8	5.4	0.4	93.9
10	1.6	-1.7	203.0	1.6	-0.5	136.0
15	-0.6	-2.3		-0.6	-1.0	

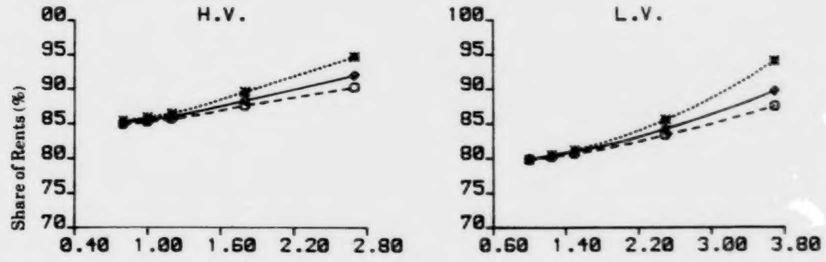
Table 6.19
Alberta (NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $5 Million Program, Collapsed Real Oil Price

Real Discount Rate (%)	No PIP			Maximum PIP (35%)		
	Expected Monetary Values (US$ million, 1986)		Government Take (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax		Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5						
0	38.4	6.8	82.4	38.4	8.0	79.2
5	20.8	2.2	89.6	20.8	3.4	83.5
10	11.8	-0.1	100.8	11.8	1.2	89.5
15	6.4	-1.4	121.7	6.4	-0.3	106.3
Overall Discovery Rate: 1 in 10						
0	16.7	2.0	87.8	16.7	3.1	81.3
5	7.8	-0.3	104.2	7.8	0.8	89.7
10	3.1	-1.5	149.1	3.1	-0.3	111.1
15	-0.3	-2.3	790.9	0.3	-1.0	410.6
Overall Discovery Rate: 1 in 20						
0	5.8	-0.3	105.8	5.8	0.7	88.3
5	1.3	-1.6	224.0	1.3	-0.5	141.0
10	-1.2	-2.3		-1.2	-1.1	-ve
15	-2.7	-2.7		-2.7	-1.5	-ve

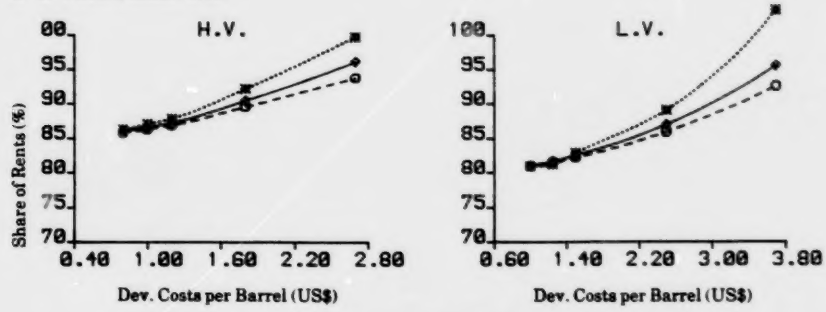
potentially distorting effects. The net result is a complex system involving checks and balances. Distortions on incentives to explore are apparent, and development of fields which are acceptable on a pretax basis could be impaired. Nevertheless, the system exhibits considerable sensitivity to changes in the operating environment and performs better in this respect than some of the schemes in other countries examined in this study.

Figure 6.58
Alberta (NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
1985 Price Perspectives
Maximum PIP (20%)

A. 10% Real Discount Rate



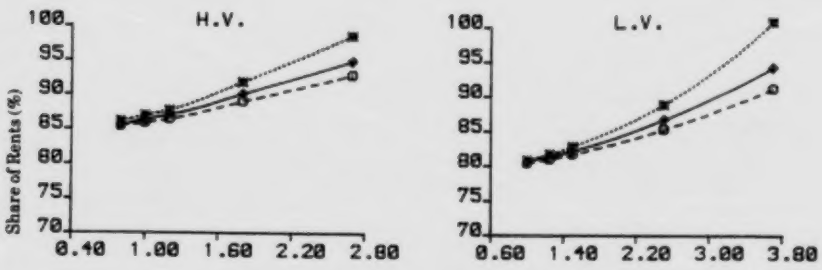
B. 15% Real Discount Rate



Legend:
——— **Constant Real Oil Price ($27)**
- - - - - **Rising Price at 2% p.a. in Real Terms**
········ **Falling Price at 2% p.a. in Real Terms**

Figure 6.59
Alberta (NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
1985 Price Perspectives
No PIP

A. 10% Real Discount Rate



B. 15% Real Discount Rate

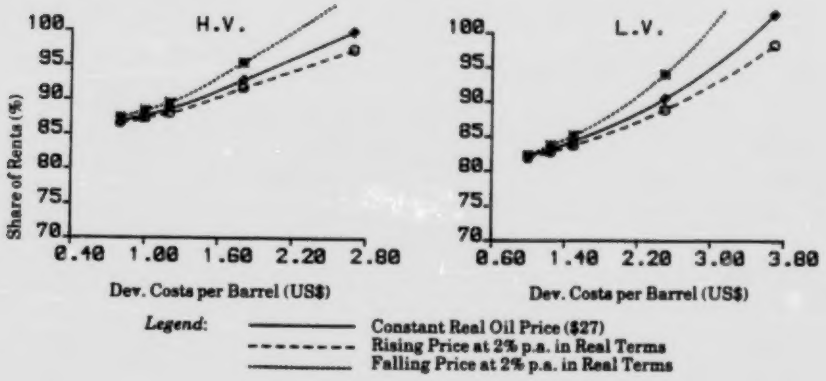
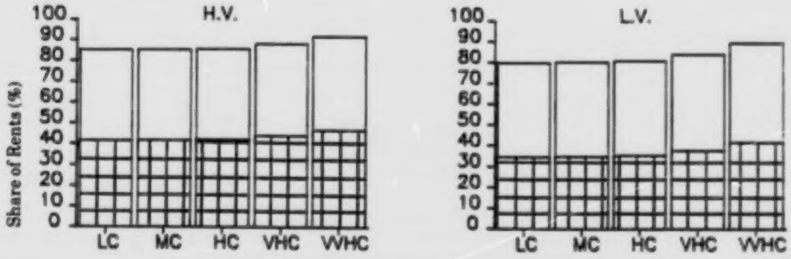


Figure 6.60
Alberta (NEP System)
Distribution of Economic Rents, 10% Real Discount Rate
Constant Real Oil Price ($27)

A. Maximum PIP (20%)



B. No PIP

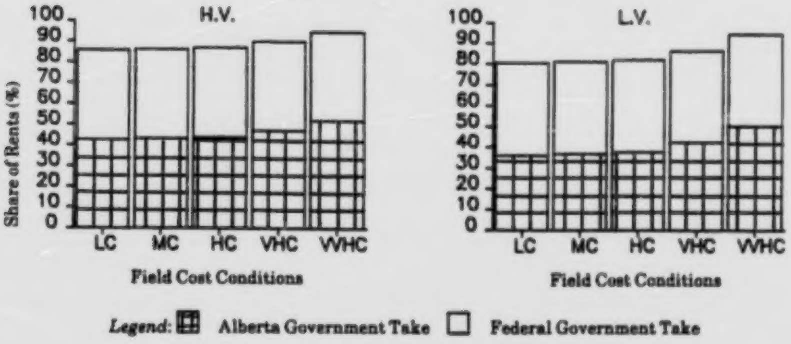
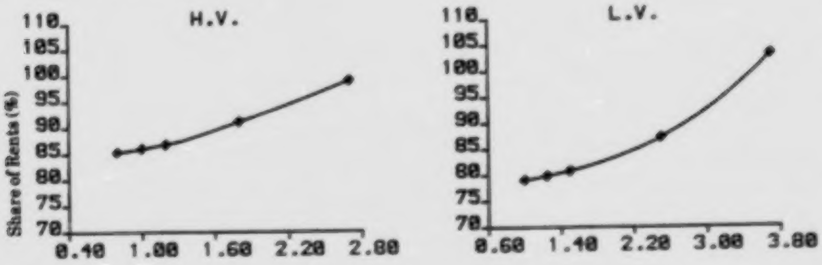


Figure 6.61
Alberta (NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
Collapsed Real Oil Price
Maximum PIP (20%)

A. 10% Real Discount Rate



B. 15% Real Discount Rate

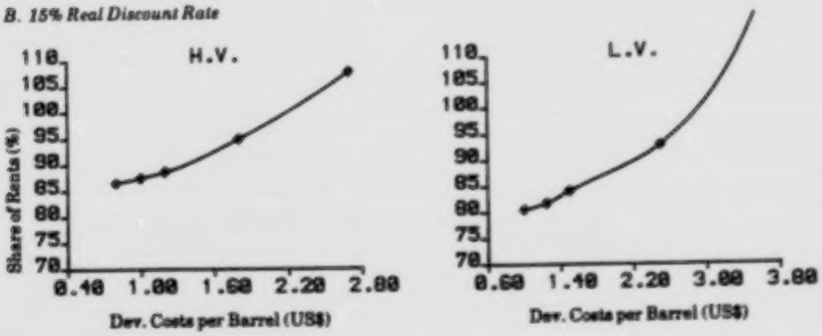
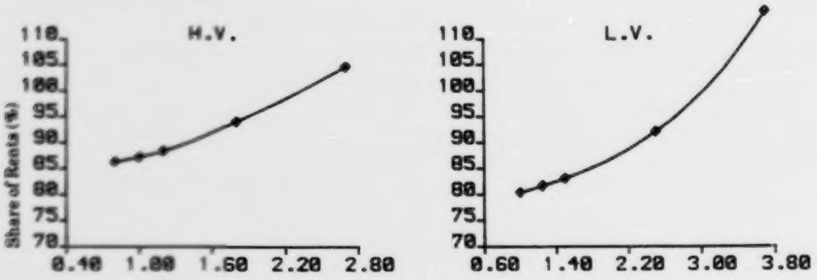
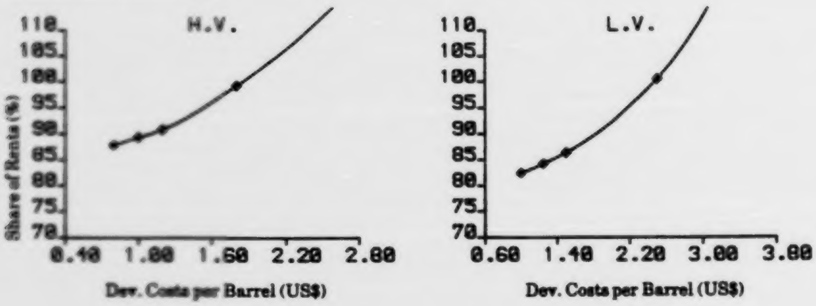


Figure 6.62
Alberta (NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
Collapsed Real Oil Price
No PIP

A. 10% Real Discount Rate



B. 15% Real Discount Rate



(c) Post-NEP System

The post-NEP system in Alberta examined here includes royalty holidays available, takes account of the changes to the royalty system made in late 1986, and includes, where appropriate, the increases in royalty tax credits and the benefits of the Exploration Drilling Assistance Program announced in April 1986. The share of economic rents accruing to the federal and Alberta governments under the 1985 oil price scenarios is shown in Figure 6.63, for discount rates of 10 and 15 per cent. The takes are seen to be mildly regressive in relation to cost changes over the most likely cost range, and more regressive under high cost conditions. Under the most likely cost conditions, government takes are proportional with regard to oil price changes and regressive under high cost conditions. The royalty formula itself leads to the regressive effect, but this is modified by the various allowances. The level of take is distinctly below that achieved under the NEP. The inclusion of the royalty-holiday provisions keeps the takes down by a perceptible amount. The LV field in particular benefits from the holiday – the overall government take is reduced by as much as five percentage points.

Under the collapsed oil price (see Figure 6.64) tax takes are reduced by a modest amount under the most likely cost conditions but are considerably higher under high-cost situations. The various royalty reliefs prevent the takes from rising under likely cost conditions, but they cannot prevent the burden rising in high-cost cases.

The front-end allowances for income tax and the early receipt of royalty reliefs greatly help to keep down the tax rate as the rate of discount is increased. The federal government is the main source of the early relief for income tax, while the Alberta government finances the several early royalty reliefs. As an example of the effectiveness of such reliefs at high discount rates, without the royalty holiday the present value of the tax take at a 20 per cent discount rate on the LV/HC field would have been 64.4 per cent whereas, with the royalty holiday, it is 51.3 per cent. The complex royalty in Alberta, with its many allowances, clearly does not behave like a conventional royalty. Nevertheless, on more marginal fields the allowances cannot prevent the government takes from rising sharply.

The change in fiscal system from NEP to post-NEP effects the split between the Alberta and federal governments. Their respective shares are shown in Figure 6.65 at 10 and 15 per cent rates of discount. The total share of rents has come down compared with the NEP scheme: the federal government's take is reduced primarily because of the abolition of the PGRT; the Alberta government has lost because of the increased allowances for royalty purposes and through the royalty holiday. Compared with the NEP system the Alberta government's position is improved in relation to the federal government's share.

The effect of the new system on the explorationist is examined, as before, for programs of $1 million, $5 million, and $10 million. The results for the $1 million program indicate that, under the 1985 oil price expectations, pre-tax and post-tax EMVs are both positive in all cases examined. The position under the $5 million program is shown in Table 6.20. The results show that exploration incentives are well maintained. There is only one negative EMV on a pre-tax basis and two after tax. With a $10 million program there are three cases of pre-tax negative EMVs and five cases on a post-tax basis. The fiscal system introduces some disincentives but they remain comparatively light. Expected tax takes rise sharply as expected profitability decreases.

Under the collapsed oil price, with a $1 million program pre-tax EMVs are positive in all cases; they remain positive on a post-tax basis, though in several cases the absolute values are tiny. The effect of a $5 million program is summarized in Table 6.21. It is seen that in this case there are two cases of negative pre-tax EMVs and five cases on a post-tax basis (including one zero outcome as negative). The fiscal system is having a negative effect. With a program costing $10 million there are five cases of negative EMVs on a pre-tax basis and nine cases in post-tax terms. Despite the many inducements, the fiscal system clearly has an adverse effect when exploration programs come into this cost bracket.

Under the post-NEP scheme a bidder contemplating an exploration program of $5 million under conditions of a 1 in 5 chance of success and employing a 10 per cent discount rate would have an EMV of $2.9 million under the collapsed oil price scenario. If he were fortunate and discovered the HV/MC field, he could expect a net present value of $80 million from developing it (assuming that he qualified for royalty holidays); if he discovered the LLV/MC field he could expect a net present value of -$0.42 million from developing it. The range of expected outcomes is thus quite wide, and the accuracy of the whole system for collecting economic rents in Alberta depends to a considerable extent on how efficiently the bidding arrangements operate.

The new fiscal system in Alberta is significantly less cumbersome than the NEP system. Nevertheless, it still retains many complexities, which are designed to reduce the crudities of the conventional royalty system. In this it succeeds to a considerable extent, even though it is not directly targeted on the economic rents derived from petroleum exploitation. The present system introduces fewer distortions to investment decisions primarily by reducing the level of take and, through a complex set of allowances, by making the royalty system less regressive than a conventional one. It could be argued that a system which was more directly targeted on economic rents could more efficiently fulfil the dual objective of removing economic rents without introducing disincentives. However, if the bidding system operates efficiently, the accuracy of the whole set of arrangements in collecting rents would be considerably enhanced.

Table 6.20
Alberta (Post-NEP System)
Expected Monetary Values and Government Takes
facing Explorationist, $5 Million Program
Constant Real Oil Price ($27)

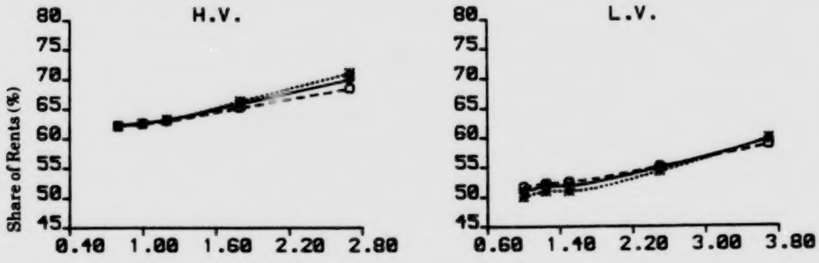
Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	65.7	24.7	62.4
5	37.5	13.2	64.9
10	23.2	7.5	67.5
15	14.8	4.3	71.1
Overall Discovery Rate: 1 in 10			
0	30.3	11.0	63.8
5	16.1	5.2	67.9
10	8.8	2.3	74.3
15	4.5	0.6	87.2
Overall Discovery Rate: 1 in 20			
0	12.7	4.1	67.3
5	5.4	1.2	78.5
10	1.6	-0.4	121.5
15	-0.6	-1.3	-

Table 6.21
Alberta (Post-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $5 Million Program
Collapsed Real Oil Price

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	38.4	13.7	64.2
5	20.8	6.5	68.6
10	11.8	2.9	75.1
15	6.4	0.8	86.9
Overall Discovery Rate: 1 in 10			
0	16.7	5.5	66.9
5	7.8	1.9	76.3
10	3.1	0.0	100.8
15	0.3	-1.1	448.3
Overall Discovery Rate: 1 in 20			
0	5.8	1.4	75.9
5	1.3	-0.5	138.5
10	-1.2	-1.5	-
15	-2.7	-2.1	-ve

Figure 6.63
Alberta (Post-NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
1985 Price Perspectives

A. 10% Real Discount Rate



B. 15% Real Discount Rate

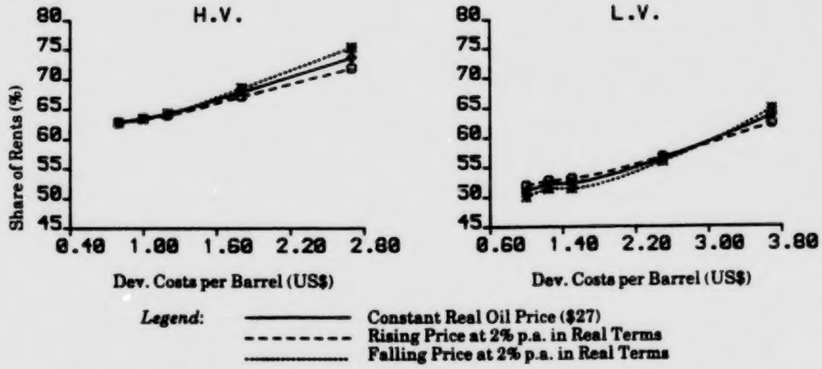
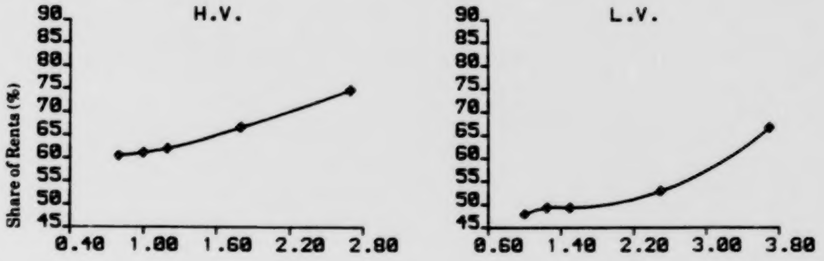


Figure 6.64
Alberta (Post-NEP System)
Government Share of Economic Rents, 10% and 15% Real Discount Rates
Collapsed Real Oil Price

A. 10% Real Discount Rate



B. 15% Real Discount Rate

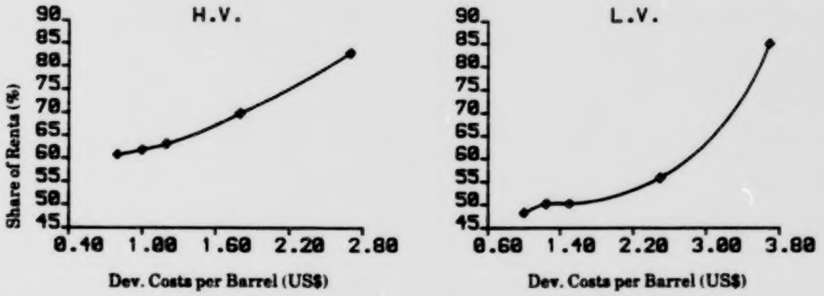
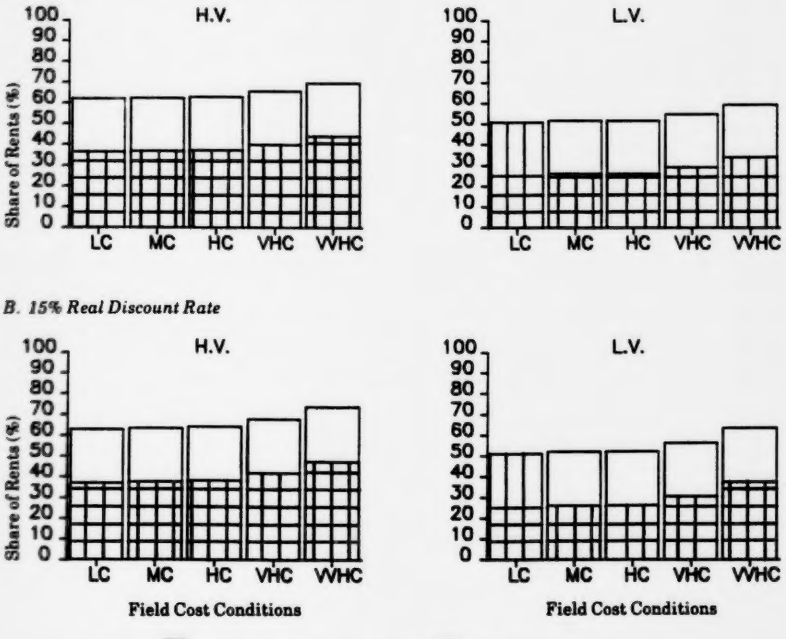


Figure 6.65
Alberta (Post-NEP System)
Distribution of Economic Rents, 10% and 15% Real Discount Rates
Constant Real Oil Price ($27)

A. 10% Real Discount Rate

B. 15% Real Discount Rate



Legend: ▦ **Alberta Government Take** ☐ **Federal Government Take**

Canada Lands

The operation of the pre-NEP, NEP, and post-NEP fiscal systems in the Canada Lands is considered separately for three different areas of vastly different size and cost conditions – the Mackenzie Delta, the Beaufort Sea, and the Atlantic Ocean.

(a) Mackenzie Delta (Onshore)

Figures 6.66 through 6.69 show net present values before tax and royalty for the Mackenzie Delta fields before and after the NEP.

Government takes at a 10 per cent discount rate are shown in Figure 6.70 for the 1985 perspective under the pre-NEP system. The scheme operates such that under highly profitable conditions the takes are proportional in relation to cost changes and progressive in relation to oil price changes on all fields examined. This is because the yield of the PIR reacts in a highly sympathetic manner to changes in profitability. The PIR in nominal terms is progressively related to profitability with respect to both oil price and cost changes. When profitability is comparatively low, however, the system becomes regressive with respect to both cost changes and oil price changes. The burden of the royalty, which is not related to profits, then becomes more pronounced and the PIR payments fall off, in the extreme reaching zero.

At the 15 per cent discount rate the pre-NEP system remains mildly progressive on the HV field until high cost conditions pertain; on the MV and LV fields the system becomes distinctly regressive and the level of take very high. Field investments could be inhibited under a combination of falling real prices and very high costs.

Under the collapsed oil price the pre-NEP system is notably regressive and the level of take very high. This is due to the non-PIR elements of the system; PIR payments fall to zero. The projects become very marginal on a pre-tax basis, and the tax system could inhibit developments at medium and high cost levels even though the absolute size of the payments may be comparatively small. At a 10 per cent discount rate the take on the HV/LC field is 60.5 per cent, on the MV/LC one 67.1 per cent, and on the LV/LC one 86.2 per cent. Under MC conditions, only the HV field is acceptable at a 10 per cent discount rate.

The pre-NEP system, while not fully targeted on economic rents, does contain features – namely, the PIR – which indirectly do relate to the appropriate target. The structure of the system is efficient as long as the PIR plays a major role in the overall burden. Under conditions of low profitability the non-PIR elements of the scheme assume greater importance and their burden can result in investment distortions being produced.

The shares of economic rents accruing to government at the 10 per cent discount rate under the NEP system (no participation), with PIP benefits being available at the maximum of 20 per cent, are shown in Figure 6.71 for the 1985 price perspective. The level of take is seen to be distinctly higher compared with the pre-NEP scheme, reflecting the PGRT burden. The system is modestly regressive with respect to both oil price and cost changes on the most profitable (HV) field. On the less profitable smaller fields the scheme is more regressive and the level of take is such that investment disincentives can be produced. The existence of two components not wholly profit-related – royalty and PGRT – explains this result.

The burden of these elements is highly sensitive to the discount rate employed. At a 15 per cent rate the level of takes is distinctly higher. On the MV/MC situation under falling real prices the take exceeds 100 per cent of the rents by a significant margin; on the LV/MC field the take reaches 100 per cent of the rents under the constant real oil price. The MC situations represent the most likely cost estimates, and so it can be concluded that the system is very likely to introduce investment disincentives even under 1985 oil price expectations.

With zero PIP benefits, the takes are higher in all situations (see Figure 6.72), to the extent that the take on the LV/MC field now significantly exceeds 100 per cent at a 10 per cent discount rate and so the project is rendered unacceptable. At a 15 per cent discount rate the level of takes becomes even higher – on the MV/MC field it is 95 per cent under a constant real oil price and greatly in excess of 100 per cent under falling real prices; in the LV/MC situation the take now exceeds 100 per cent.

Under the NEP system, participation by Petro Canada adds to government take. Under highly or moderately profitable circumstances this adds several percentage points to the overall take. For example, on the HV/LC field the take goes up by six to seven percentage points with a 10 per cent discount rate under the constant ($27) real oil price scenario. Under conditions of low profitability with high discount rates, the total government take can actually be reduced because the government is effectively sharing in present-value losses as well as gains.

Under the collapsed-price scenario the NEP system produces very high levels of tax takes, with the system also being very regressive. On the HV/LC field the tax take is 80.6 per cent with a 10 per cent discount rate; under MC conditions on the same size of field the take reaches 141 per cent. On the MV/LC field the take is 101.5 per cent; on the LV/LC one, 145.5 per cent. Pre-tax profitability is, of course, fairly low under this price scenario and the tax system is not at all well geared to prevent investment disincentives from emerging.

The operation of the fiscal system under low oil prices is best seen by considering its impact in money-of-the-day terms. This is shown in Figure 6.73, where PIP benefits of 20 per cent are included. It is seen that when modest profits are being earned (HV field under LC and MC conditions), the system is broadly proportional. The progressive PIR, the (modest) allowances for the PGRT, and the PIP benefits are together sufficient to ensure that regressive element (conventional royalty) does not dominate the take. Under situations of low profitability, however, the non-profit-related elements dominate the structure of the system. The result is that the scheme becomes regressive, significant payments are still required, and the take becomes very high. When PIP benefits are excluded and Petro Canada participation included, the total take under LC conditions is extremely high. Under MC and HC conditions the state is sharing in substantial present-value losses.

The NEP system in Canada Lands is thus not well structured to deal with large changes in the operating environment. The progressive element (the PIR) can be swamped by the royalty and PGRT, which are not related to profitability. The system is not well structured to deal with the range of profitability, including some projects only marginally attractive that can be expected in the Mackenzie Delta. The system as a whole is not closely related to economic rents, and when nominal rates become high the likelihood of distortions emerging increases substantially.

The post-NEP system is substantially different in its impact from the NEP one. The share of economic rents collected by government from fields in the Mackenzie Delta under the post-NEP system is shown in Figure 6.74 for a 10 per cent discount rate under the 1985 oil price perspective. The level of take is considerably lower. On the profitable HV field the take is proportional with respect to cost conditions and mildly progressive with respect to oil price changes. This result follows from the front-end income-tax reliefs for field investment to an ongoing investor, as well as the fact that the production-related elements of the royalty payments are comparatively small.

On the MV and LV fields the takes are generally proportional with respect to cost changes in the LC to MC range and mildly progressive or proportional with respect to oil price changes. The level of take is in the 57 to 62 per cent range. The results reflect the structural features discussed above operating in situations of moderate profitability. At cost levels in excess of the MC level, field profitability is comparatively low and the component of the royalty based on wellhead values rather than on cash flows assumes higher significance. It will be recalled that this component starts at a 1 per cent rate and rises to 5 per cent (in increments of 1 per cent every 18 months) until project payout is achieved. The lower the level of profitability, therefore, the longer the period in which payments based on production will be made. The result is that the system becomes increasingly regressive the lower the level of profitability.

Government takes remain sensitive to discount rates employed. With a 15 per cent rate (see Figure 6.75) the scheme becomes mildly regressive on the profitable HV field when HC conditions are attained, but the level of take increases much more dramatically on the less profitable smaller fields. At high discount rates the relative importance of production-based impositions is increased because of the early timing of the payments. When projects become fairly marginal, the weight of even quite small early payments can become highly significant.

Under the scenario of collapsed oil prices, the post-NEP system is extremely regressive and can attain very high levels. At a 10 per cent discount rate on the HV field, the take is 59 per cent under LC and 75 per cent under MC conditions; at higher levels of cost it exceeds 100 per cent. On the MV field the take is 67.3 per cent under LC conditions and exceeds 100 per cent at MC. On the LV field the take is 76 per cent at LC and greatly exceeds 100 per cent under MC circumstances.

The operation of the system with collapsed oil prices can be seen from Figure 6.76, which shows the tax takes in money-of-the-day terms. On the more profitable HV field the system remains very mildly progressive or proportional. On the smaller fields, at the higher cost levels the system becomes highly regressive and the level of take very high. When profits are very low even modest production-based charges can have a severe effect and will result in distortions to investment in marginally acceptable fields.

The effect of the post-NEP system on exploration is considered for a program of $70 million. Table 6.22 summarizes the case where the new system (no participation and excluding any PIP grant) is applied to an explorationist contemplating such a program in the onshore Mackenzie Delta area, assuming a constant real oil price of $27. Pre-tax EMVs are negative in six of the cases examined, and these remain negative (though to a lesser extent) on a post-tax basis. The positive values are significantly reduced by the tax system, but the cost-sharing features of the system, particularly the incentives regarding exploration expenditures, are so valuable that the negative present-value losses are reduced. The expected tax takes are comparatively moderate in level and the system is not very regressive with respect to discount rates or to geological prospectivity. The front-end reliefs for exploration expenditures play an important role here. Under an exploration program of $210 million, pre-tax EMVs are generally negative, usually by very large amounts. The reliefs for exploration ensure that expected tax takes remain comparatively modest.

Table 6.22
Mackenzie Delta (Onshore) (Post-NEP System)
Expected Monetary Values and Government Takes
facing Explorationist, $70 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986) Pre-Tax	Post-Tax	Government Take (%)
Overall Discovery Rate: 1 in 5			
0	236.6	99.4	58.0
5	102.9	42.5	58.7
10	29.2	10.2	65.2
15	-15.8	-10.1	-
Overall Discovery Rate: 1 in 10			
0	83.3	35.7	57.1
5	14.7	6.6	55.4
10	-23.9	-10.3	-
15	-48.2	-21.1	-
Overall Discovery Rate: 1 in 20			
0	6.6	3.8	42.1
5	-29.4	-11.4	-
10	-50.4	-20.6	-
15	-64.3	-26.7	-

An explorationist contemplating a $70 million program with a 1 in 5 chance of success, if he employs a 10 per cent discount rate, has a post-tax EMV of $10.2 million under the scenario of constant real oil price of $27. If the discovered field were the HV/LC one, the net present value obtained from developing it would exceed $550 million. On the other hand, if the LV/HC field were discovered, the net present value that would ensue would be $17.8 million. The eventual distribution of the rents between the government and the investor depends to a considerable extent on the operation of the bidding system.

Under the collapsed oil price, pre-tax EMVs with the $70 million program are negative in all cases examined. Post-tax values are all negative but, again, the losses are reduced by the exploration reliefs available under this scheme. Similar findings prevail under the larger exploration program. Thus, as far as exploration is concerned, the new system introduces very valuable incentives which will frequently compensate for the distorting structure of the tax payments, which are not well related to profitability.

In the frontier areas PIP grants are still temporarily available under the grandfathering provisions. When the PIP grants are at 80 per cent, the incentive effect remains strong. At the collapsed oil price the effect of this system is more powerful than the incentive results in the scheme discussed above. The reliefs for exploration expenditure and the front-end allowances together are so strong that it is possible to find cases where the investor's expected losses are less after tax than they are before tax – this happens where the reliefs for the expenditure are very high in present-value terms and the tax take on an expected discovery comparatively low.

In sum, the new fiscal system for Canada Lands is more lenient than its predecessor and distorting effects on investment decisions are therefore less likely to emerge. Structurally, the new system is less dominated by imposts based on gross revenues. The fiscal weapons are still not targeted directly on economic rents, however, and, given the marginal nature of some of the prospects in the Mackenzie Delta, investment disincentives can readily emerge. Because of the generous reliefs for exploration, disincentives at the exploration stage are much less likely to be caused by the fiscal system than by the inherent unprofitability of the ventures on a pre-tax basis.

Figure 6.66
Mackenzie Delta (Onshore) (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

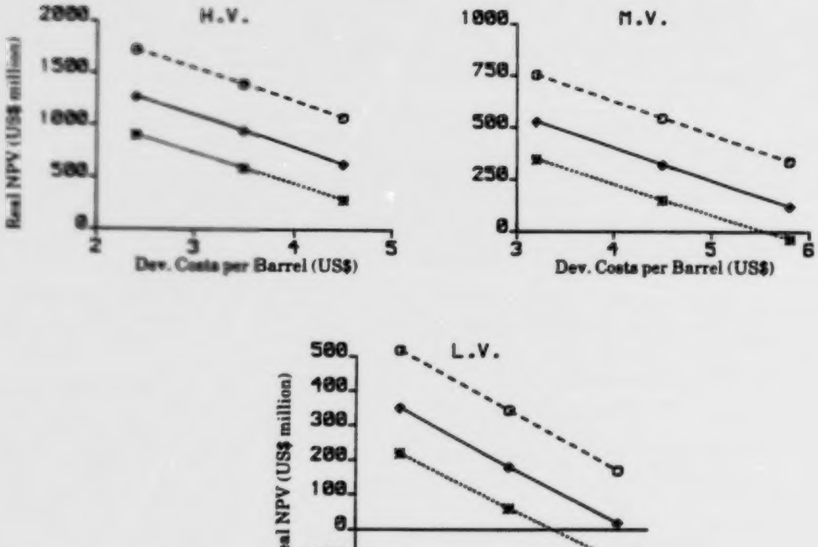


Figure 6.67
Mackenzie Delta (Onshore) (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

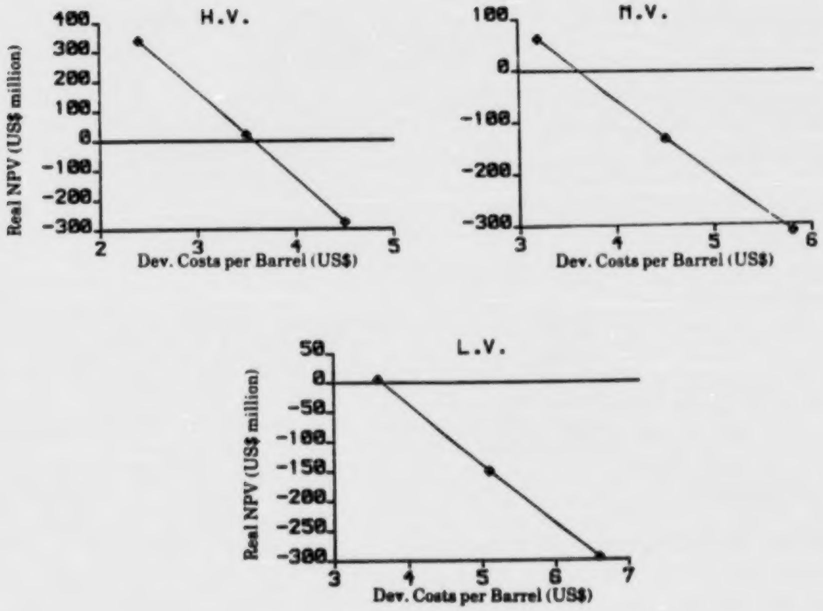


Figure 6.68
Mackenzie Delta (Onshore) (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

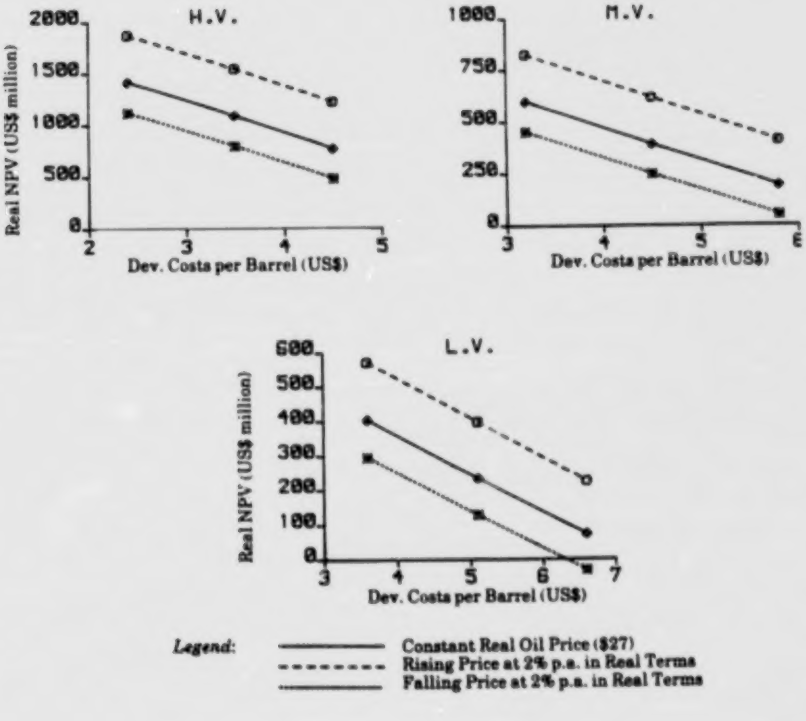


Figure 6.69
Mackenzie Delta (Onshore) (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

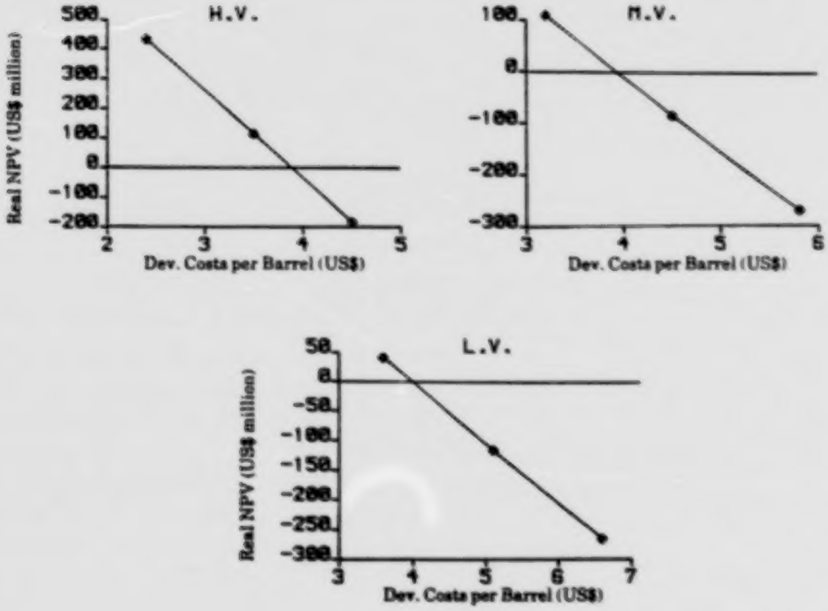


Figure 6.70
Mackenzie Delta (Onshore) (Pre-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

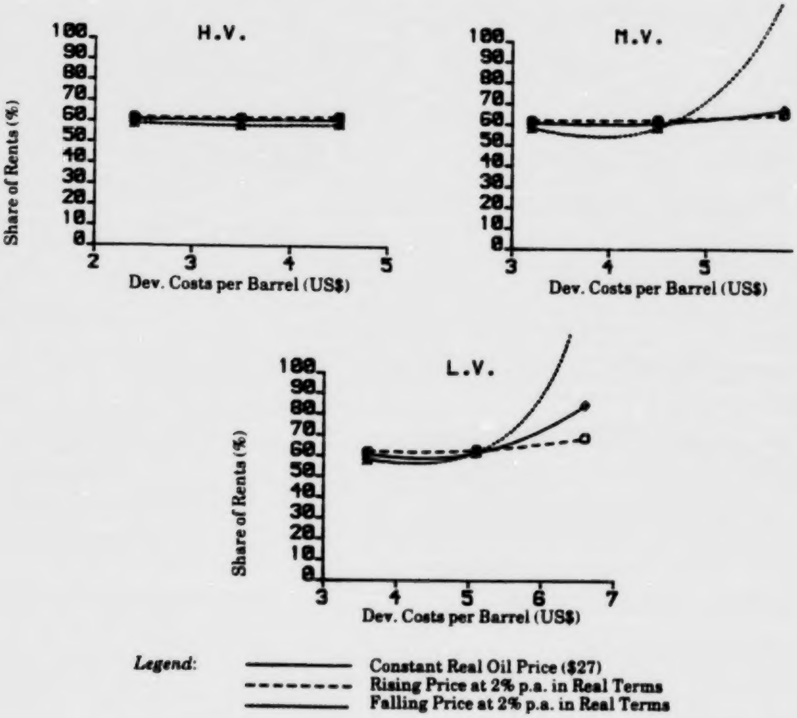


Figure 6.71
Mackenzie Delta (Onshore) (NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives
Maximum PIP (20%)

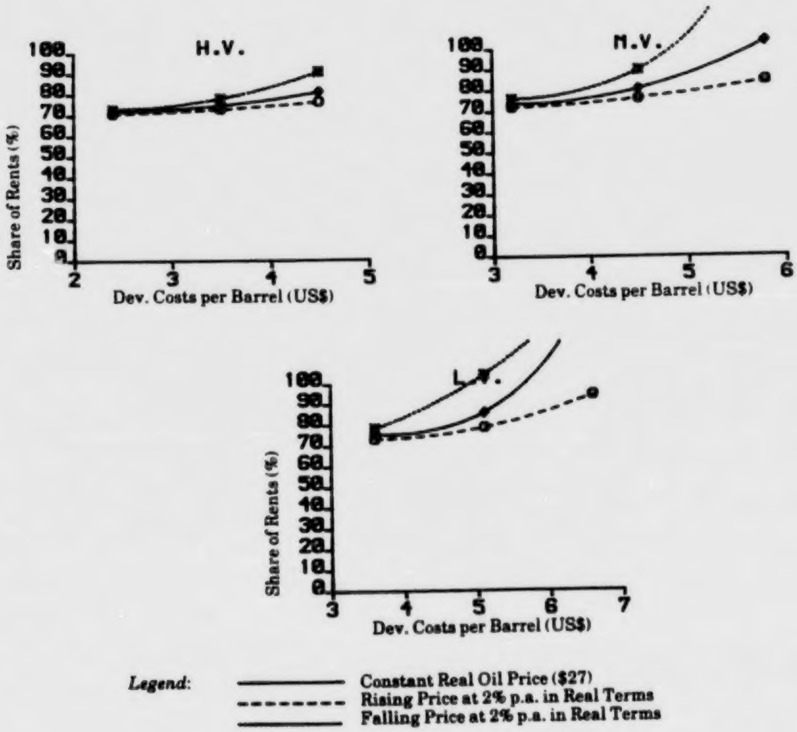


Figure 6.72
Mackenzie Delta (Onshore) (NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives
No PIP

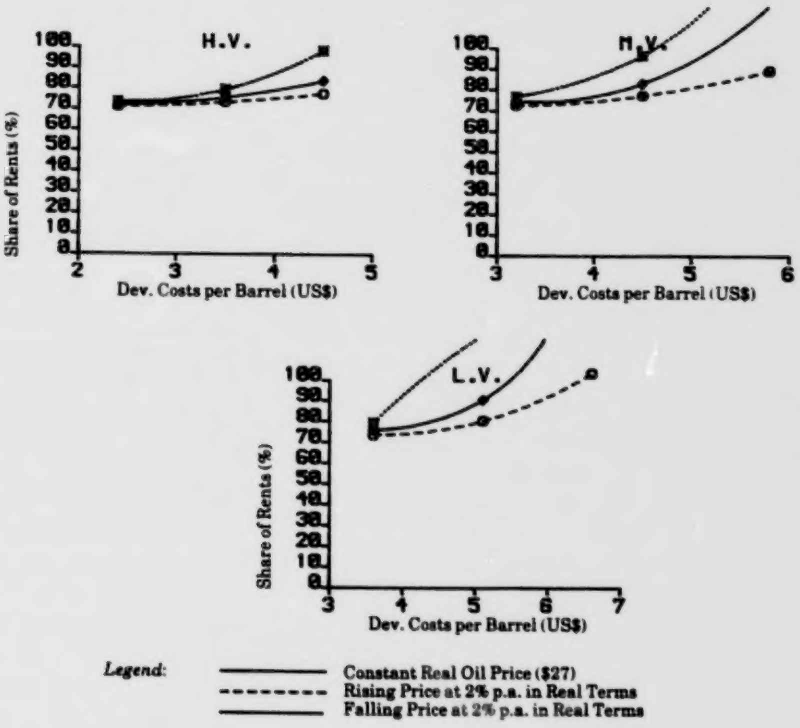


Figure 6.73
Mackenzie Delta (Onshore) (NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price
Maximum PIP (20%)

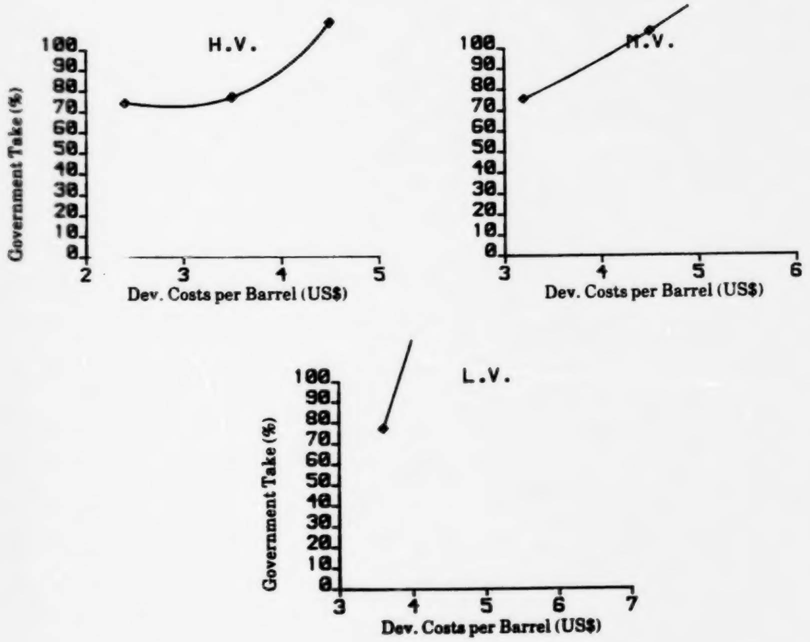


Figure 6.74
Mackenzie Delta (Onshore) (Post-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

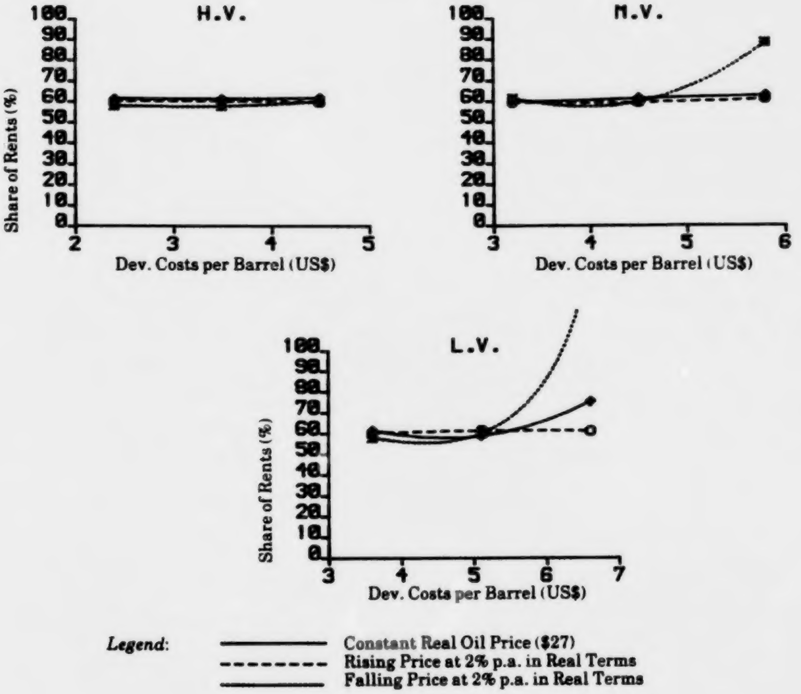
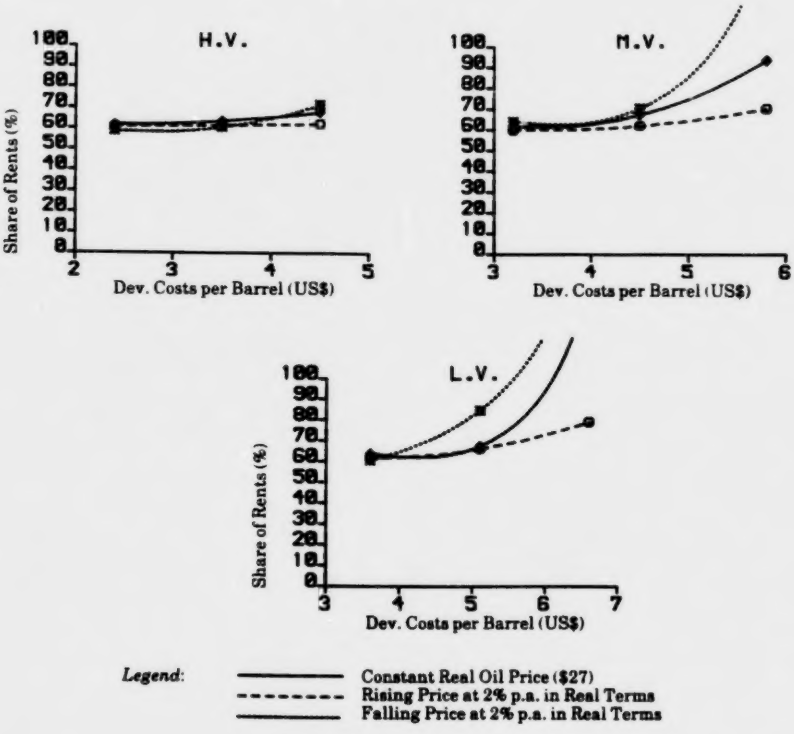


Figure 6.75
Mackenzie Delta (Onshore) (Post-NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives



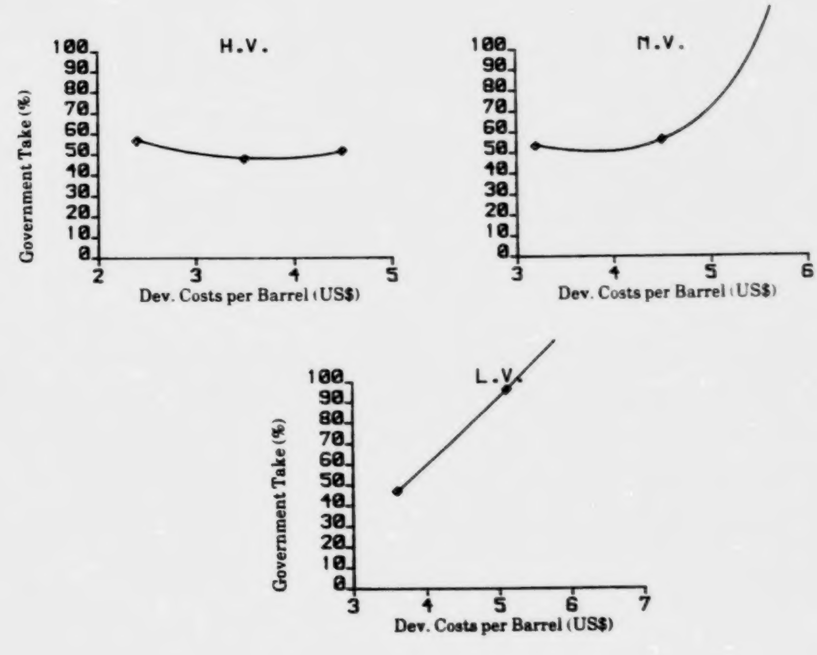


Figure 6.76
Mackenzie Delta (Onshore) (Post-NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price

(b) Beaufort Sea

The pre-tax net present values at 10 per cent discount rate facing investors in the Beaufort Sea are shown in Figures 6.77 through 6.80 for the pre-NEP, NEP, and post-NEP systems, under the four price scenarios.

Government shares of economic rents under the pre-NEP fiscal system for the 1985 oil price scenarios with a 10 per cent discount rate, are shown in Figure 6.81. The system is seen to be generally progressive with respect to oil prices and cost conditions. The system remains comparatively efficient in structure and moderately lenient in level due to a combination of the progressive PIR and the front-end reliefs for field investment expenditures. The high initial capital investment required and the reliefs available for these expenditures play a dominant role in determining the effective tax take. The reliefs include the allowances for development costs available to an ongoing investor for income tax, as well as the investment tax credit. The PIR is, of course, progressively related to profitability. The conventional royalty is regressive, but its effects are outweighed by the other progressive elements.

Under higher discount rates the effects of the initial capital outlays and the front-end reliefs available for them become even more dominant in determining the overall fiscal burden. The position with a 15 per cent discount rate is shown in Figure 6.82.

At discount rates of 10 per cent and 15 per cent the tax takes remain progressive on the comparatively large fields in the Beaufort Sea in relation to both oil price and cost changes. Because the fields are much larger than those in the Mackenzie Delta, they enjoy economies of scale in their exploitation and are thus inherently more profitable. In these circumstances the conventional, regressive royalty does not constitute a major element in the fiscal package. Another reason the burden of the royalty is comparatively low is that the transportation charges, which are very high from the Beaufort Sea, are deductible in order to obtain the base royalty value.

Under the collapsed oil price, the pre-NEP fiscal system applied to Beaufort Sea fields remains comparatively lenient and progressive in structure. While the profitability of the projects is greatly reduced, the availability of front-end reliefs for the capital expenditure, together with the continued operation of the progressive PIR, ensures that the overall system remains progressive. The operation of the system is best seen by examining its impact in money-of-the-day terms, as shown in Figure 6.83, which demonstrates the distinct progressiveness of the scheme. The front-end reliefs for capital expenditure are, of course, included in the calculation. The result is that the fiscal system by itself does not cause any significant inhibition in investment. Under the collapsed oil price, investment incentives are considerably reduced but this is because the projects become much less attractive on a pre-tax basis.

Figure 6.84 shows the share of economic rents accruing to government under the NEP scheme with PIP benefits at 20 per cent, at a 10 per cent discount rate under the 1985 oil price scenarios. On the profitable HV and MV fields the take is seen to remain remarkably constant, at around 65 per cent, under changing oil price and cost conditions. The introduction of the PGRT constitutes a regressive element in the fiscal package but, despite this and the conventional royalty, the system remains proportionally related to the changing economic rents. This is because other elements in the package produce counteracting influences: the progressive nature of the PIR and the existing front-end reliefs for investment have already been noted; the PIP benefits are now added, and the result is a very complicated mechanism which has the net effect of producing a take proportional to the economic rents. It is seen from Figure 6.84 that in the less profitable LV field the scheme produces a mildly regressive system under high costs. In such situations the PIR becomes a small component of the total take and the other, non-profit-related elements (conventional royalty and PGRT) become relatively more important; the result is a mildly regressive scheme.

The behaviour of the system also becomes less efficient at higher discount rates. This is seen from Figure 6.85, which shows the position with a 15 per cent rate. The scheme is still proportional in the LC to MC range but becomes distinctly regressive under the higher cost situations, when the early fiscal payments (conventional royalty and PGRT) assume higher importance in the fiscal take and the various allowances and incentive payments are insufficiently strong to prevent the take from rising sharply, especially under the falling real oil price. It is seen from Figure 6.85 that the take can exceed 100 per cent and possibly cause investment disincentives.

In Beaufort Sea conditions the PIP benefits are an important component of the overall fiscal package, and the position of an investor who is not eligible to receive them is adversely affected to a significant degree. With a 10 per cent discount rate the overall government take is not noticeably increased, but at a 15 per cent rate the burden becomes distinctly greater, as can be seen in Figure 6.86. The level of take increases substantially on the less profitable situations, exceeding 100 per cent in several cases.

Under the collapsed-price scenario the NEP system with PIP benefits at 20 per cent and a discount rate of 10 per cent remains broadly proportional in the LC to MC range but becomes extremely regressive at higher cost levels. This is shown in Figure 6.87. At higher discount rates the take is at a higher level, the system becomes more regressive, and investment disincentives can certainly be produced. In the absence of PIP benefits the system is noticeably more regressive and the level of take considerably higher, with the result that further investment disincentives could be produced.

Participation by Petro Canada adds to total government take under the NEP scheme. The effect is to increase overall take by several percentage points under highly to moderately profitable operating conditions without introducing any obvious investment disincentives. Under the 1985 perspective on the HV and MV fields, government take increases considerably. At lower levels of profitability, however, there is a smaller net increase in take. Eventually, under the collapsed oil price, the result of continued participation would be a sharing of the present-value losses between Petro Canada and the private investor.

In sum, on fields of comparatively high profitability the NEP system operates to produce a moderate government take. The scheme is not sufficiently flexible in dealing with major changes in the operating environment, particularly the existence of projects of modest profitability. In these circumstances the production-related elements in the package assume increasing dominance over the profit-related elements.

The share of economic rents accruing to government under the post-NEP scheme (no participation) is shown in Figure 6.88 for the 1985 oil price perspective at a 10 per cent discount rate. The scheme is seen to be somewhat progressive in its impact, and the level such that investment disincentives do not emerge. The front-end reliefs for capital investment to an ongoing investor make a strong impact at the higher levels of cost and prevent the take from rising. The production-based element in the royalty remains comparatively small since the fields are relatively profitable and the large transport costs mean that the royalty base is quite low. At a 15 per cent discount rate the takes do not increase noticeably. The front-end investment reliefs and the continuing low level of effective royalty explain this result.

Under the collapsed-price scenario the fiscal system continues to react in a reasonably sympathetic manner. While the profitability of the projects is much reduced, the government take at the 10 per cent discount rate does not become onerous, principally due to the continued benefits for investment expenditure and the comparatively low burden of the royalty. As is indicated in Figure 6.89, in money-of-the-day terms the system remains progressive because of the complex set of allowances and the small size of the effective royalty payments.

The effects of the post-NEP system to be considered by an explorationist contemplating a program costing $210 million are shown in Table 6.23 (no participation). The results indicate that, under the 1985 oil price perspective, pre-tax EMVs are healthily positive except under low prospectivity and high discount rates. The tax system is seen to collect a moderate share of the expected rents and to maintain incentives when pre-tax expectations are not satisfactory. The substantial front-end reliefs (including the PIP grandfathering arrangements) play a major role in maintaining exploration incentives.

Table 6.23
Beaufort Sea (Post-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $210 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	1759.6	789.4	55.1
5	884.4	415.8	53.0
10	401.9	201.3	49.9
15	114.6	68.5	40.3
Overall Discovery Rate: 1 in 10			
0	774.8	352.8	54.5
5	331.8	163.8	50.6
10	85.1	54.4	36.1
15	-64.3	-14.3	36.1
Overall Discovery Rate: 1 in 20			
0	282.4	134.4	52.4
5	55.6	37.8	31.9
10	-73.3	-19.1	-
15	-153.7	-55.6	-

The position under the collapsed oil price, for the same size of exploration program, is shown in Table 6.24. Pre-tax EMVs are frequently negative, but the exploration incentives in the fiscal package are very strong, ensuring that the expected tax takes are comparatively low and that overall exploration incentives are not impaired. By comparison with many other countries, the fiscal treatment of exploration in the Beaufort Sea is very sympathetic. With a smaller exploration program ($70 million) pre-tax EMVs under the collapsed price are negative in four of the cases examined, and these cases remain negative after tax. The expected tax take is again comparatively moderate due to the substantial exploration incentives, which ensure that the overall system does not introduce obvious distortions to exploration activity.

Table 6.24
Beaufort Sea (Post-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $210 Million Program
Collapsed Real Oil Price

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	435.0	272.2	42.1
5	108.3	97.6	18.2
10	-80.0	-7.4	-
15	-196.1	-74.3	-
Overall Discovery Rate: 1 in 10			
0	112.5	94.1	27.6
5	-56.2	4.7	-
10	-155.9	-50.0	-
15	-219.6	-85.6	-
Overall Discovery Rate: 1 in 20			
0	-48.8	5.1	-
5	-138.5	-41.7	-
10	-193.8	-71.2	-
15	-231.4	-91.3	-

In sum, for the investment situations likely to be faced by investors in the Beaufort Sea the post-NEP fiscal package produces a net effect that is distinctly sympathetic to investors. The package remains very complex and the individual elements are not well related to economic rents. For an ongoing investor, however, the system of checks and balances produces a net result whereby the state collects only a moderate share of economic rents and economic distortions are generally not produced. The current disincentives to invest in the Beaufort Sea are primarily due to projects' being unattractive on a pre-tax basis.

Figure 6.77
Beaufort Sea (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

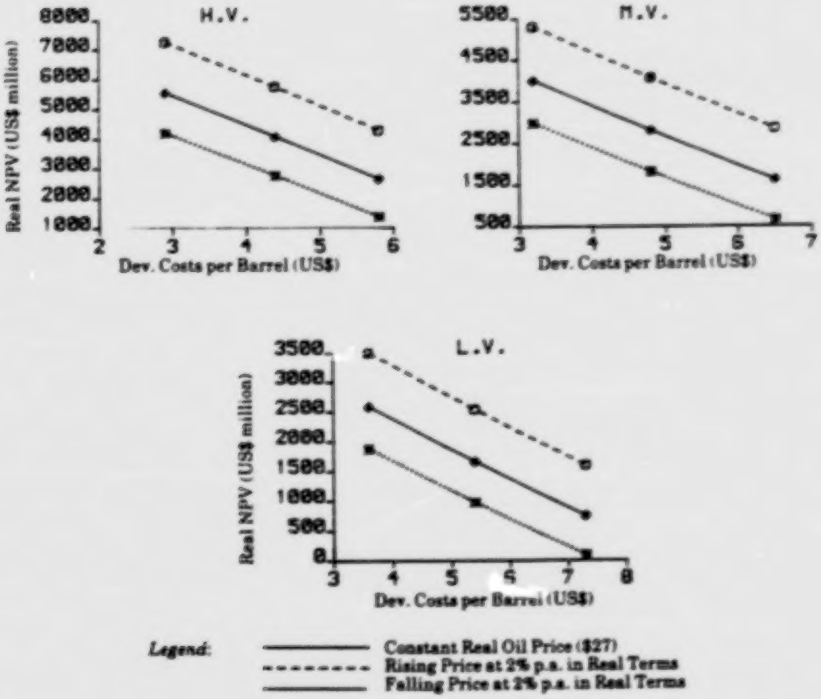


Figure 6.78
Beaufort Sea (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

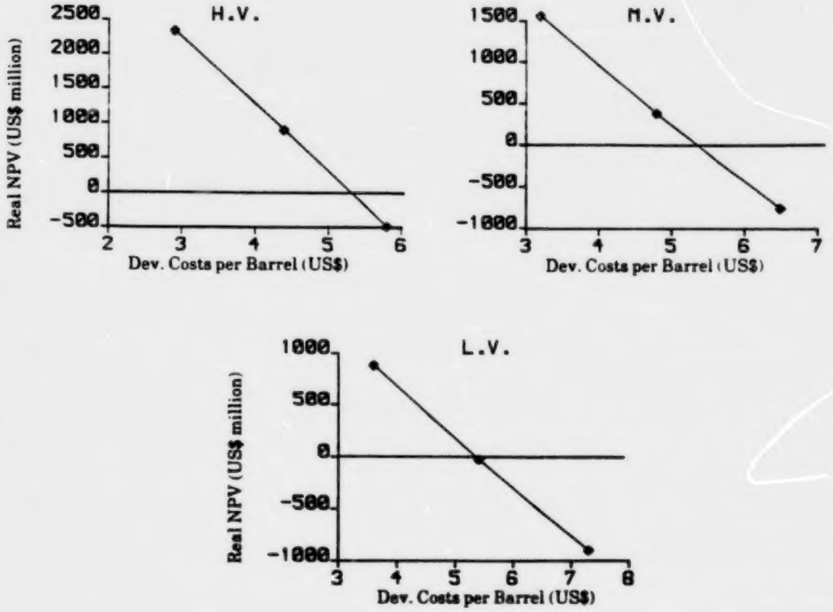


Figure 6.79
Beaufort Sea (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

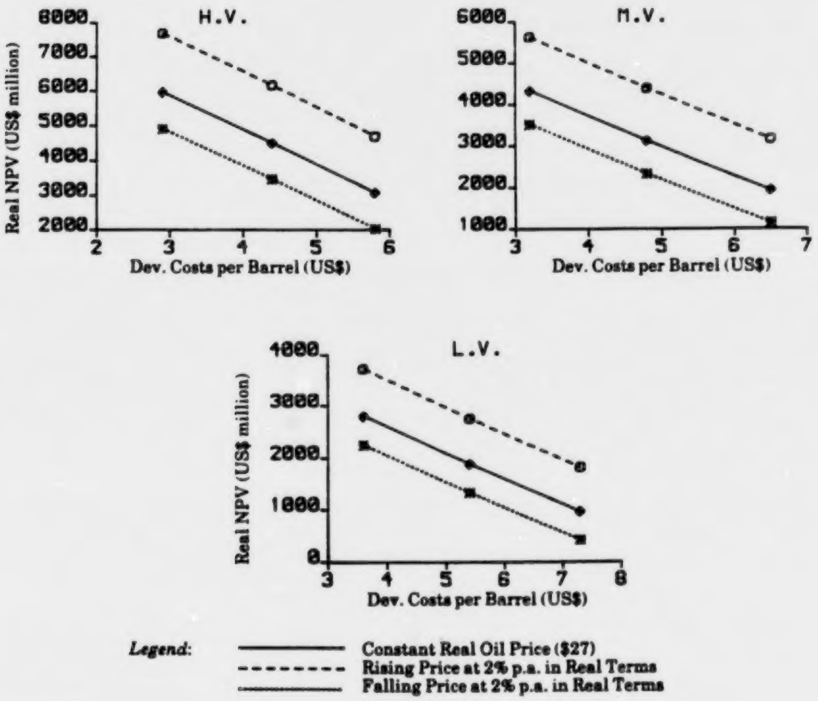


Figure 6.80
Beaufort Sea (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

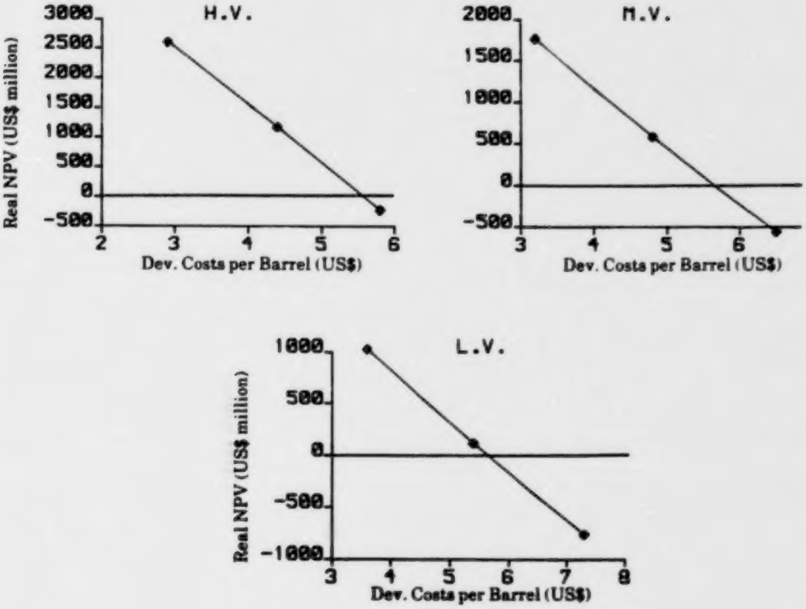


Figure 6.81
Beaufort Sea (Pre-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

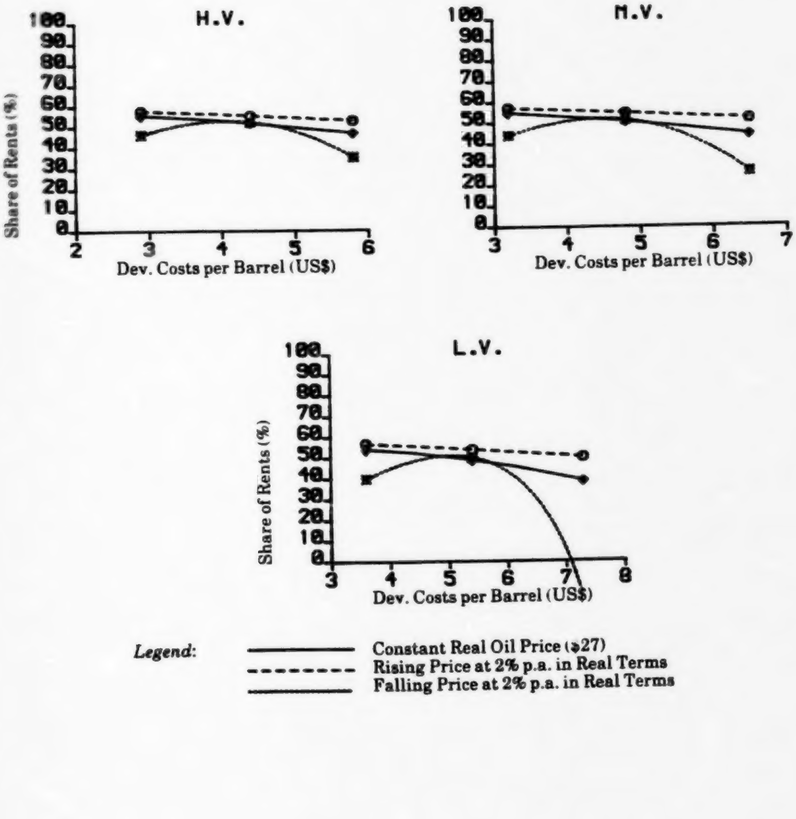


Figure 6.82
Beaufort Sea (Pre-NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

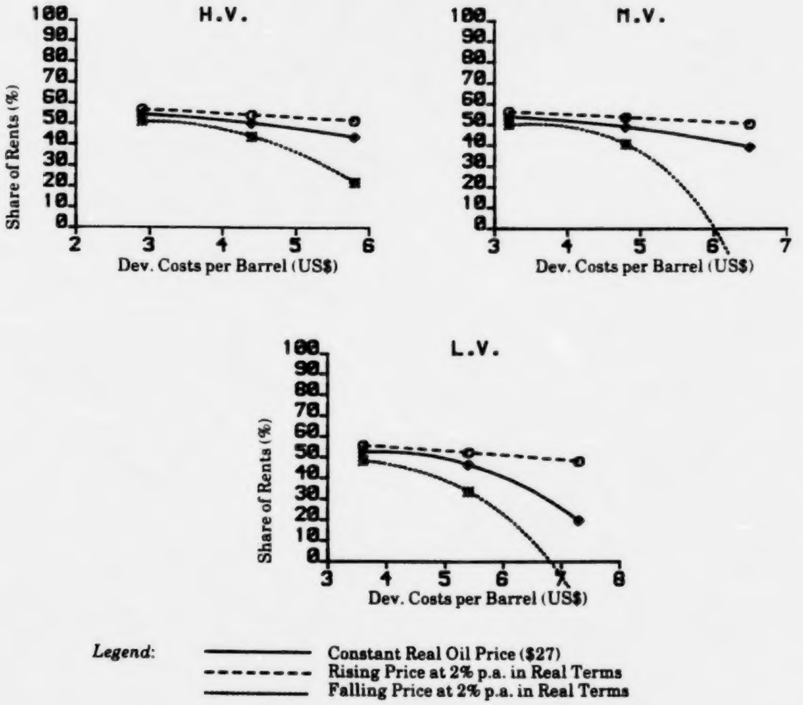


Figure 6.83
Beaufort Sea (Pre-NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price

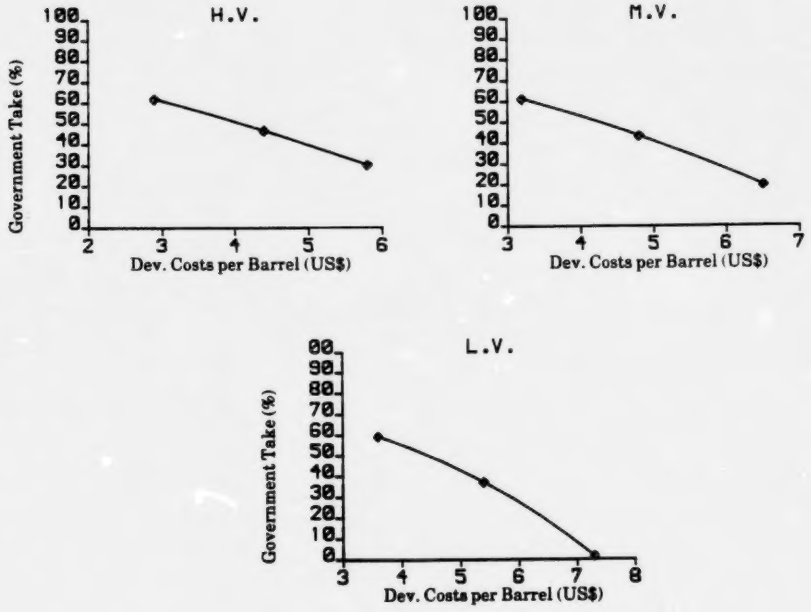


Figure 6.84
Beaufort Sea (NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives
Maximum PIP (20%)

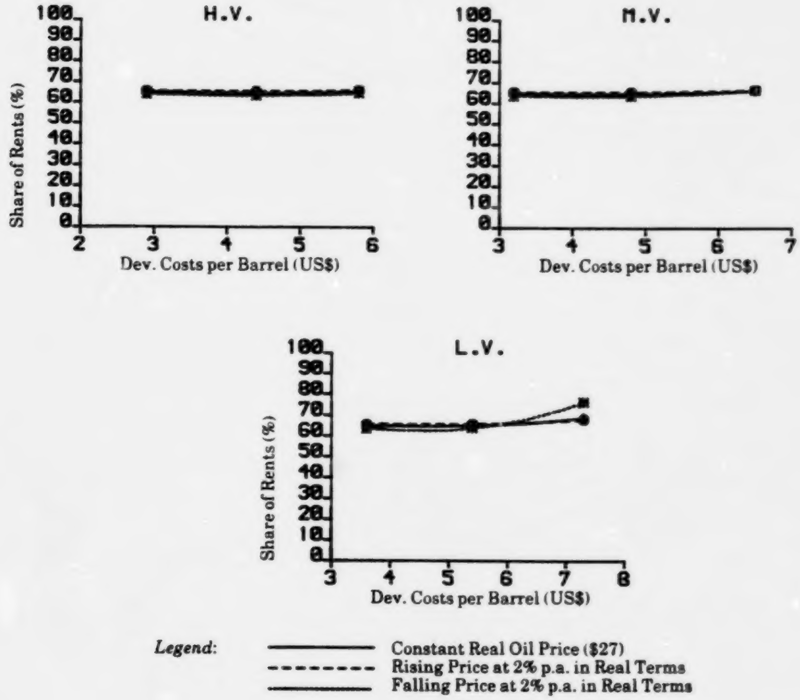


Figure 6.85
Beaufort Sea (NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives
Maximum PIP (20%)

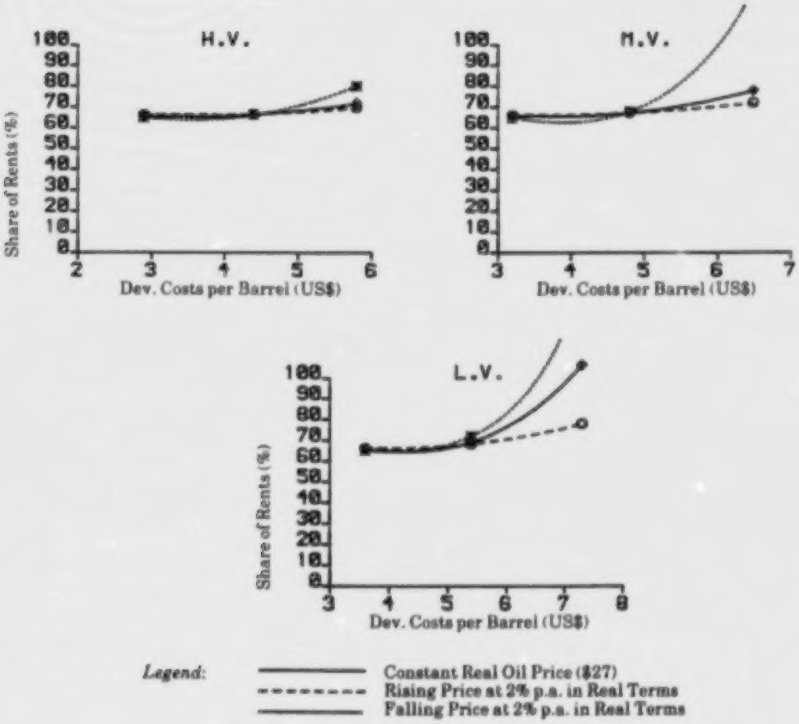


Figure 6.86
Beaufort Sea (NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives
No PIP

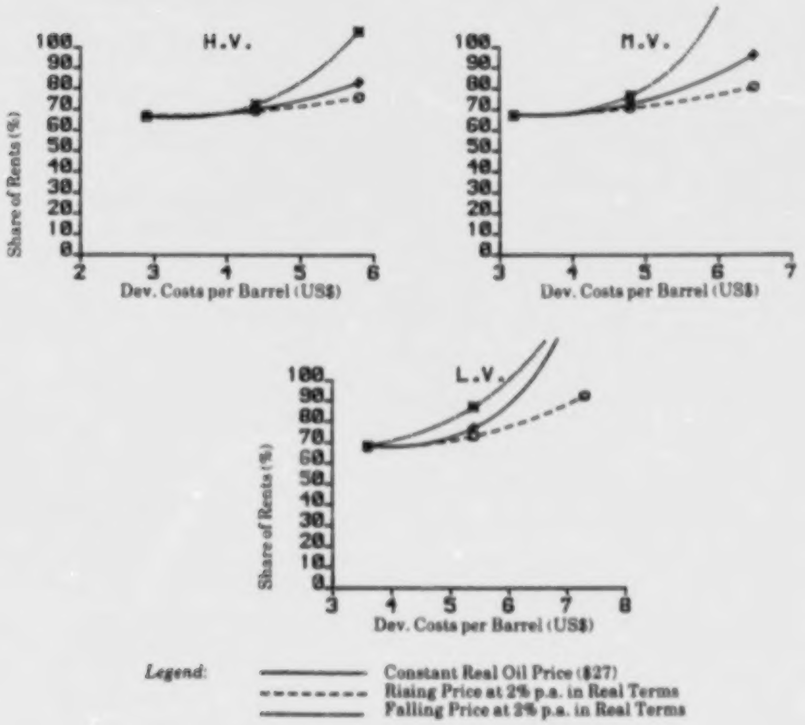


Figure 6.87
Beaufort Sea (NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
Collapsed Real Oil Price
Maximum PIP (20%)

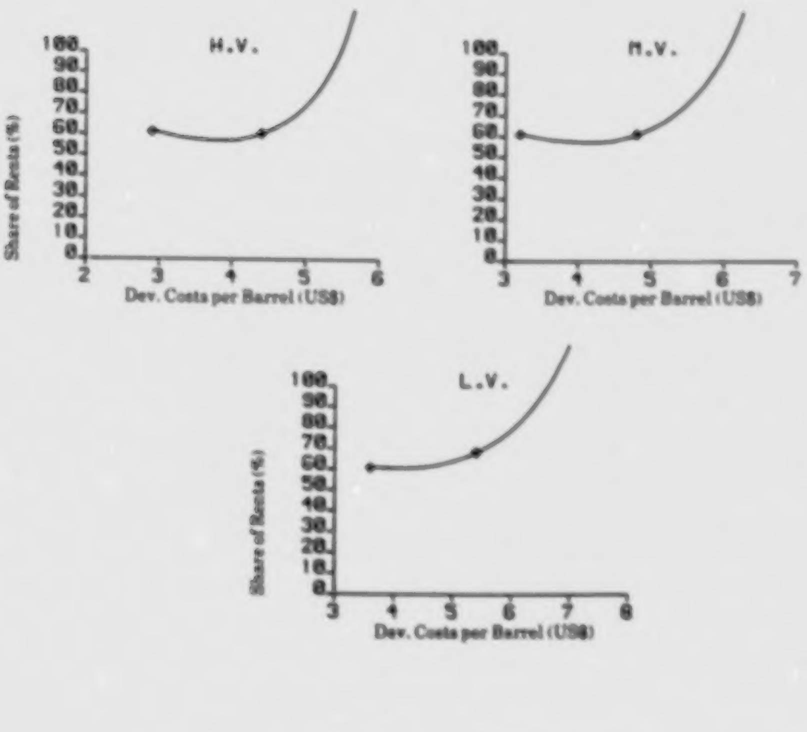


Figure 6.88
Beaufort Sea (Post-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

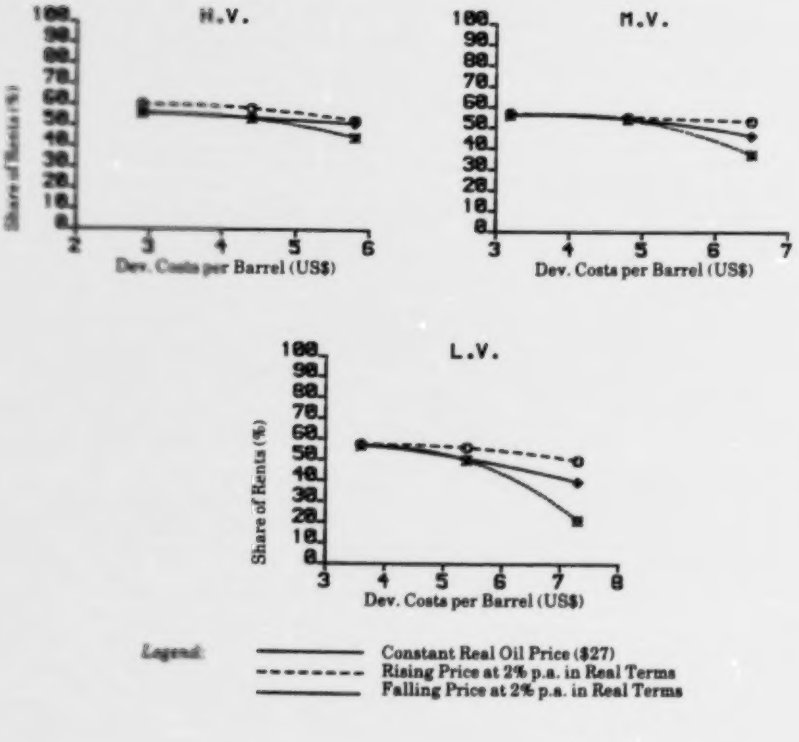
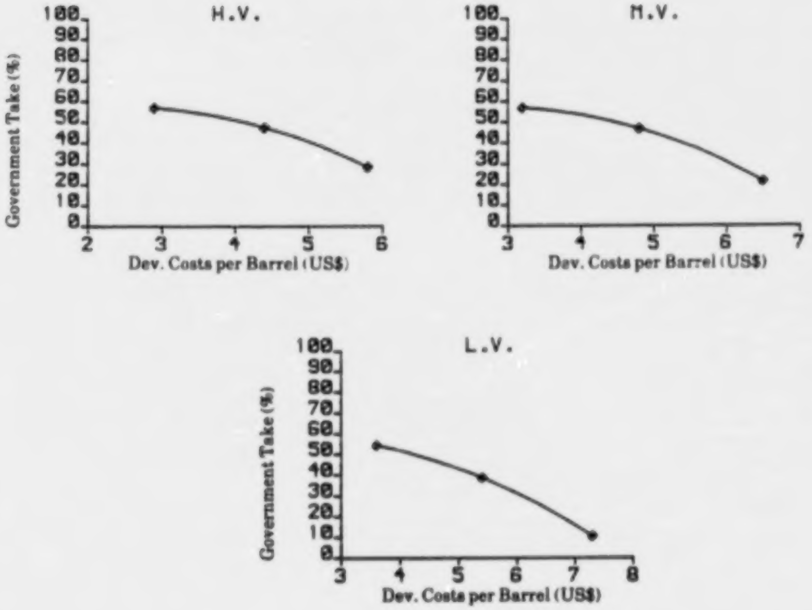


Figure 6.89
Beaufort Sea (Post-NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



(c) Atlantic Ocean

Pre-tax net present values (discount rate 10 per cent) facing investors in the Atlantic Ocean under the pre- and post-NEP systems are shown in Figures 6.90 through 6.93 for the 1985 and collapsed-price scenarios.

Figure 6.94 shows the shares of economic rents taken by government under the pre-NEP system for Canada Lands, for the 1985 oil price perspectives at a 10 per cent discount rate. The system is seen to be regressive, with a high level of take. Under the falling real price, the take attains levels in excess of 100 per cent and thus could introduce investment distortions. Under situations of moderate and low profitability the burden of the conventional royalty becomes noticeably high. The transport deductions for the royalty are considerably lower for Atlantic Ocean locations than they are for the Beaufort Sea, and this has a noticeable effect in pushing up the burden of this impost.

At low levels of profitability the PIR is not payable. Under higher oil price scenarios it is payable and helps to introduce a progressive element. Similarly, the front-end allowances for capital expenditure, including the investment tax credit, prevent the system from becoming both regressive and severe. Under higher discount rates these progressive elements are swamped by the impact of the conventional royalty. This is seen in Figure 6.95 for a 15 per cent rate; the system becomes highly regressive and the level of take exceeds 100 per cent of the rents in many situations.

Under the collapsed oil price the projects in the Atlantic Ocean are not very profitable on a pre-tax basis (see Figure 6.91). At the 10 per cent discount rate economic rents are available on the three fields only under LC conditions. The government take at 10 per cent discount rate is 74 per cent on the HV/LC field, 87.5 per cent on the MV/LC one, and 249.2 per cent on the LV/LC one. The system is regressive in discounted terms.

In sum, the pre-NEP system applied to Atlantic Ocean fields operates in such a way that economic disincentives can be caused not only under the collapsed oil price but, under some circumstances, under the 1985 price perspective as well. The projects are not very profitable on a pre-tax basis; in such cases the conventional royalty can play a significant role in introducing distortions.

The share of rents taken by government under the NEP system where PIP benefits at 20 per cent are available is shown in Figure 6.96 at 10 per cent discount rate for the 1985 oil price perspective. The level of take is very high, the system is regressive, and investment disincentives can readily emerge. The projects are large, and considerable amounts of conventional royalty and PGRT are payable. The burden of these is sufficiently high that they more than offset the progressive elements – such as the PIR, the investment tax credit, and PIP benefits. The system becomes more severe under less profitable situations if PIP benefits are not available. At higher discount rates the level of take is higher and the degree of regressiveness greater.

Under the collapsed-price scenario the projects are not very profitable even before tax. Under LC conditions the share of the rents collected at the 10 per cent discount rate is 82 per cent on the HV field, 91.9 per cent on the MV one, and 317.8 per cent on the LV one. The system is highly regressive in present-value terms. The structure of the scheme under low prices in money-of-the-day terms is seen in Figure 6.97. Even in nominal terms, takes are high and the structure regressive even though project profitability is low.

When Petro Canada participation is added, the overall government share increases by several percentage points under profitable situations. Under the more common situations of low post-tax profitability, the result of participation is that the state company shares with the investor in the present-value losses.

In sum, the NEP system is found to be insufficiently sensitive to the operating environment in the Atlantic Ocean to constitute an efficient mechanism for extracting economic rents. Some of the instruments, particularly the PGRT and conventional royalty, are not directed at economic rents. Their impact becomes substantial under low oil price scenarios, and disincentives can readily be produced. Because the level of tax is high, the need for accurate targeting is greater if distortions are to be avoided.

The share of rents collected by government under the post-NEP system (no participation) is shown in Figure 6.98 from the 1985 price perspective, for a 10 per cent discount rate. The level of take is seen to be much lower than under the NEP scheme. Further, the system is progressive, especially under situations of low profitability. The burden of the production-based component of the royalty is outweighed by other features of the fiscal package under the constant and falling price scenarios; the front-end reliefs for capital expenditure, including the substantial investment tax credit, exceed the value of all tax payments in present-value terms. In situations of very low profitability the discounted take becomes negative.

At a 15 per cent discount rate the take under the rising real oil price is somewhat higher and the system becomes mildly regressive (see Figure 6.99). Under the constant and falling price scenarios, on the other hand, both the take and the (gross) economic rents become negative. The fiscal system as a whole is thus responsive to changes in the operating environment.

Under the collapsed oil price, at 10 per cent discount rate, government take is 49.8 per cent on the HV/LC field and 52.3 per cent on the MV/LC one. In present-value terms there are no other net tax payments in this scenario. In money-of-the-day terms taxes are still payable, however; their structure and level are shown in Figure 6.100.

The position of an explorationist in the Atlantic Ocean contemplating a program costing $70 million is shown in Table 6.25

Table 6.25
Atlantic Ocean (Post-NEP System)
Expected Monetary Values and Government Takes facing Explorationist, $70 Million Program
Constant Real Oil Price ($27)

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	1509.0	587.2	52.9
5	424.2	206.9	51.2
10	82.5	42.9	48.0
15	-65.7	-30.5	53.6
Overall Discovery Rate: 1 in 10			
0	719.5	279.6	52.5
5	175.4	88.8	49.4
10	2.7	2.1	-
15	-73.1	-31.4	-
Overall Discovery Rate: 1 in 20			
0	324.8	125.8	51.4
5	50.9	29.7	41.7
10	-37.1	-12.4	-
15	-76.8	-31.8	-

for the 1985 oil price perspective. There are negative pre-tax EMVs only under high discount rates or low prospectivity. The tax system generally results in moderate levels of take, and there are no cases where positive pre-tax values are turned into negative ones after tax. The substantial front-end-loaded incentives for exploration play an important role here, as does the generally sympathetic fiscal system applied to discoveries. Under a bigger program, $210 million, pre-tax EMVs become negative in seven of the scenarios. The fiscal system again does not produce extra disincentives; no positive outcomes are turned into negative ones, and the expected tax take on positive outcomes varies from 41 to 50 per cent.

Under the collapsed oil price, the position facing an explorationist contemplating a program costing $70 million is shown in Table 6.26. It is seen that the pre-tax EMVs are generally negative by substantial margins, but the fiscal system remains sympathetic in its treatment of the explorationist. No positive values are turned into negative ones, and the expected tax take on positive outcomes remains

Table 6.26
Atlantic Ocean (Post-NEP System)
Expected Monetary Values and Government Takes
facing Explorationist, $70 Million Program
Collapsed Real Oil Price

Real Discount Rate (%)	Expected Monetary Values (US$ million, 1986)		Government Take (%)
	Pre-Tax	Post-Tax	
Overall Discovery Rate: 1 in 5			
0	107.7	60.0	44.3
5	-11.1	-2.3	-
10	-62.0	-23.3	-
15	-85.4	-35.2	-
Overall Discovery Rate: 1 in 10			
0	18.8	16.0	15.1
5	-42.3	-13.6	-
10	-69.5	-27.0	-
15	-82.9	-33.7	-
Overall Discovery Rate: 1 in 20			
0	-25.6	-6.0	19.1
5	-57.9	-21.5	-
10	-73.3	-28.9	-
15	-81.7	-33.0	-

at modest levels. A similar picture emerges for other sizes of exploration program. Through the various front-end reliefs, the government is sharing in the investment risks to a very considerable extent in Atlantic Ocean exploration. Clearly, the overwhelming reason for the decline in exploration in the Atlantic Ocean is the lack of profitability on a pre-tax basis.

In sum, the post-NEP fiscal system applied to the Atlantic Ocean usually does not produce investment disincentives. While the whole system is not directly targeted on economic rents, the structure of allowances, particularly the large front-end reliefs for both development expenditures and exploration, produces a net result whereby a fluctuating share of the rents is collected and the chances of disincentives emerging are fairly low.

Figure 6.90
Atlantic Ocean (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

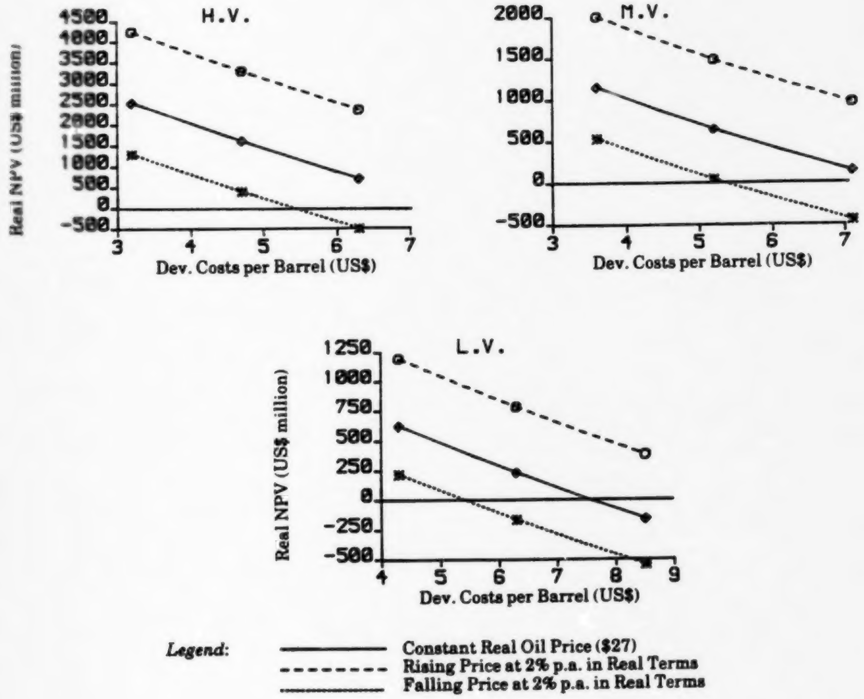


Figure 6.91
Atlantic Ocean (Pre-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

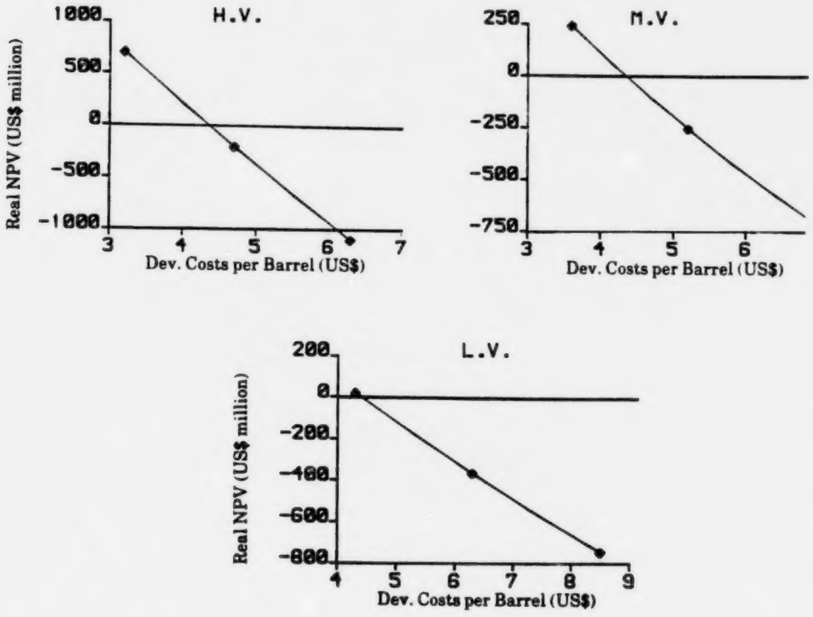


Figure 6.92
Atlantic Ocean (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
1985 Price Perspectives

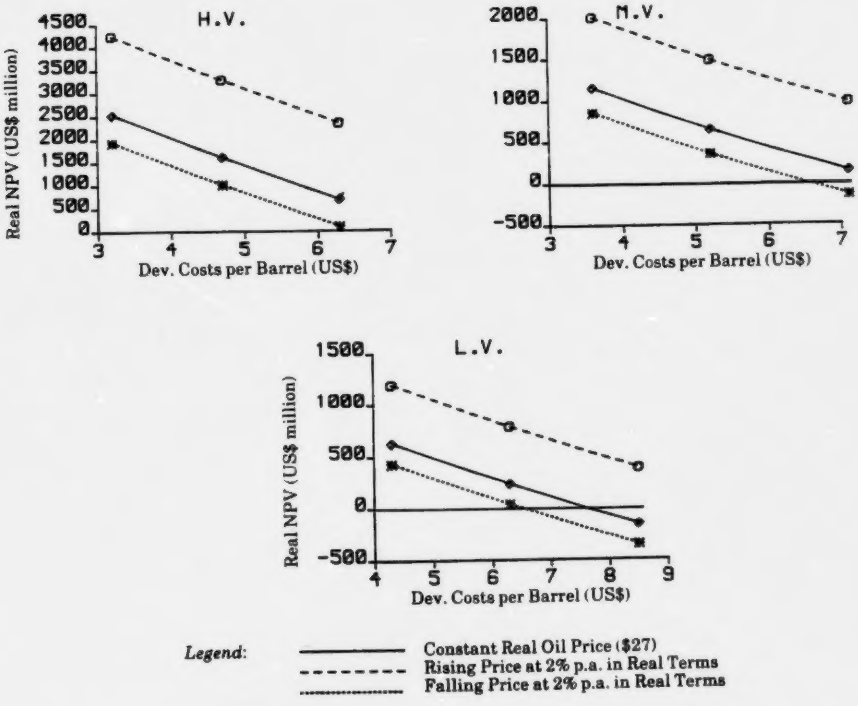


Figure 6.93
Atlantic Ocean (NEP/Post-NEP)
Real Net Present Values, 10% Real Discount Rate (no taxes or royalty)
Collapsed Real Oil Price

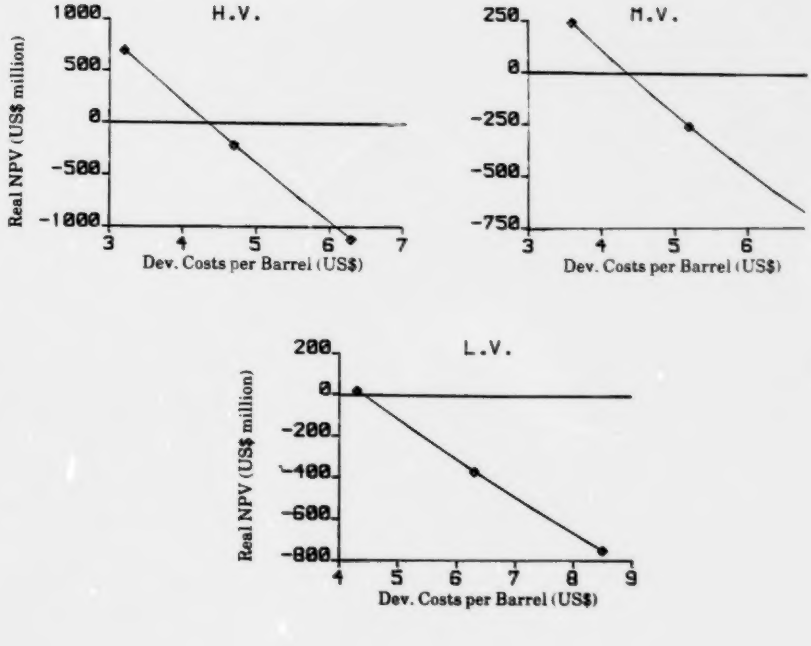


Figure 6.94
Atlantic Ocean (Pre-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

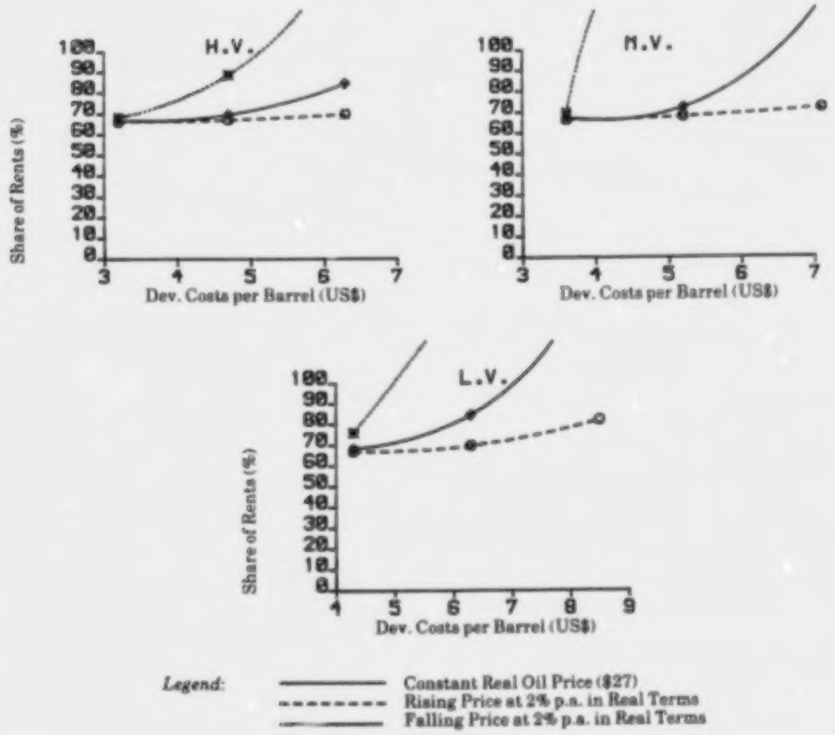


Figure 6.95
Atlantic Ocean (Pre-NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1986 Price Perspectives

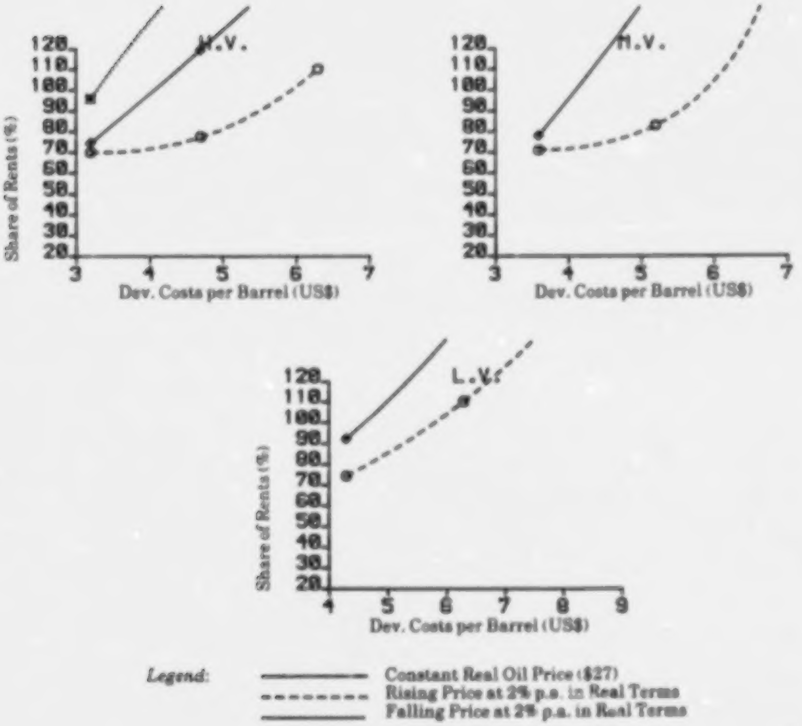


Figure 6.96
Atlantic Ocean (NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives
Maximum PIP (20%)

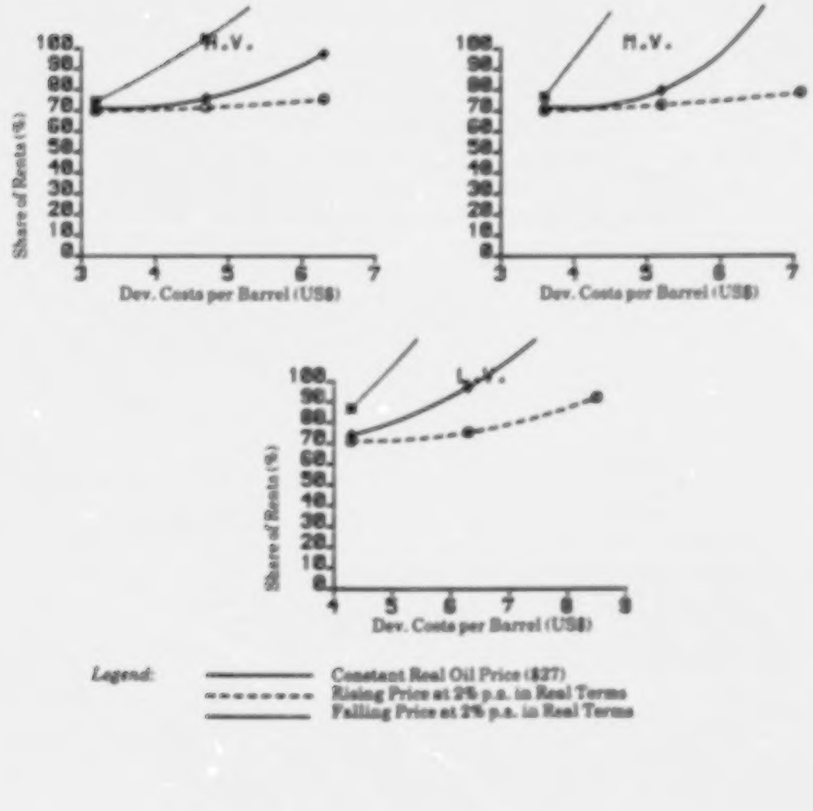
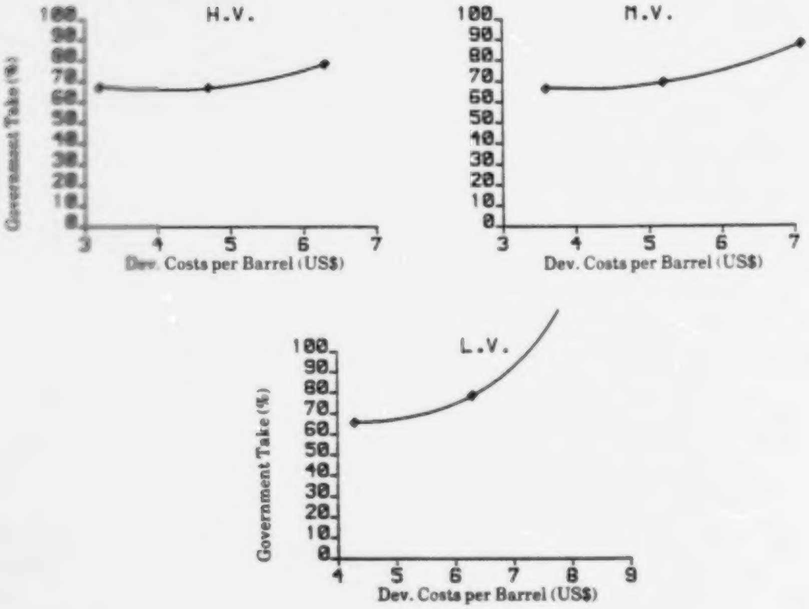


Figure 6.97
Atlantic Ocean (NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price
No PIP



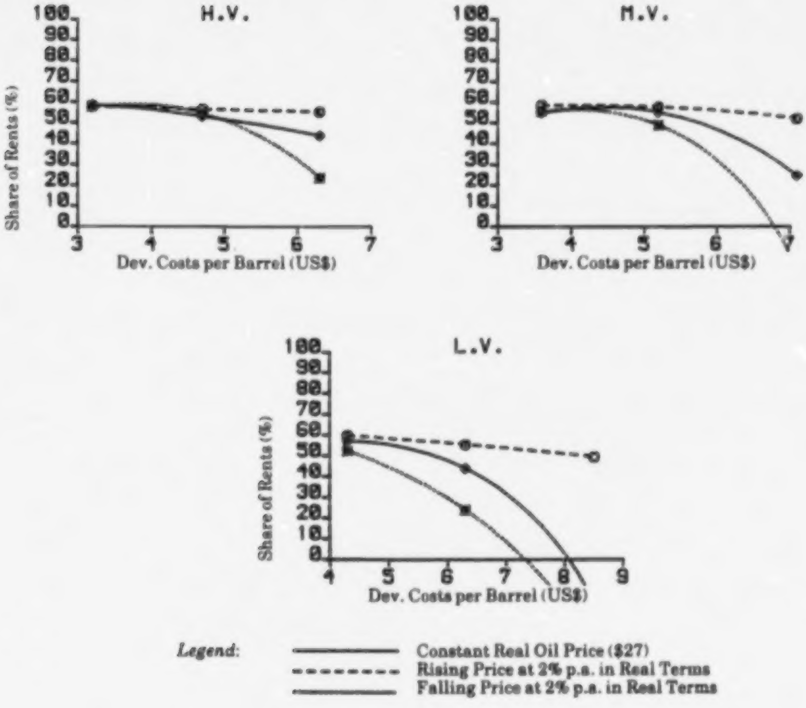


Figure 6.98
Atlantic Ocean (Post-NEP System)
Government Share of Economic Rents, 10% Real Discount Rate
1985 Price Perspectives

Figure 6.99
Atlantic Ocean (Post-NEP System)
Government Share of Economic Rents, 15% Real Discount Rate
1985 Price Perspectives

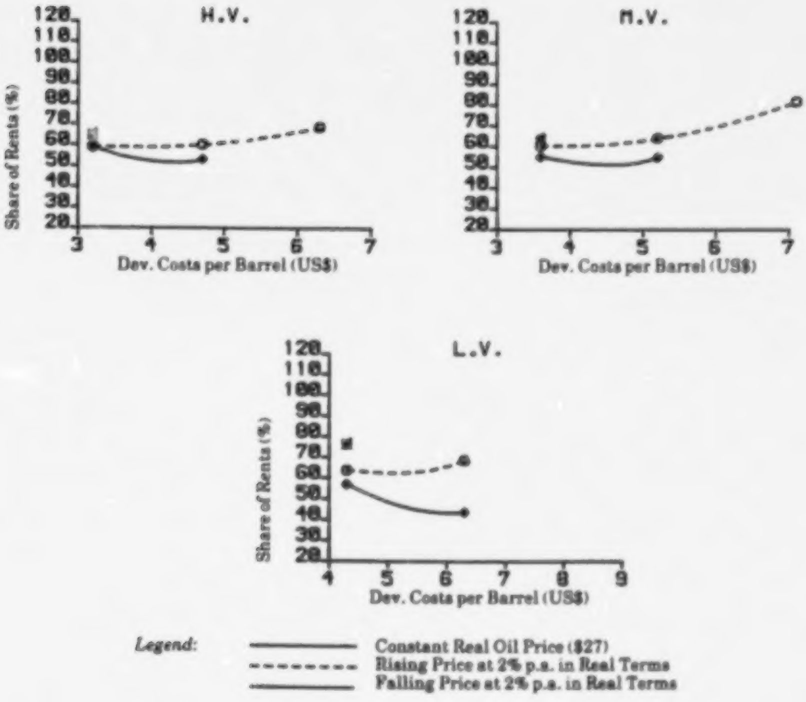
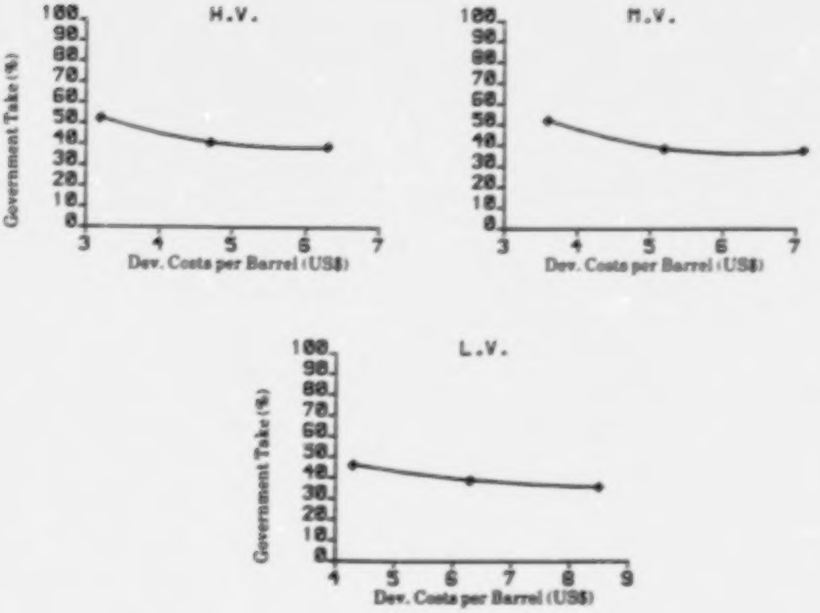


Figure 6.100
Atlantic Ocean (Post-NEP System)
Nominal Government Take (as percentage of resources generated)
Collapsed Real Oil Price



Chapter 7

Summary and Conclusions

Economic Rents in the Petroleum Industry

For many years the collection of economic rents from petroleum exploitation has been a subject of much concern to governments of all countries containing petroleum reserves. The attainment of this objective in an economically efficient manner turns out to be a complex issue. Difficulties exist in defining economic rents in theory and measuring them in practice, and further difficulties exist in designing a scheme that will efficiently extract them for the state. Since governments are unable accurately to measure the appropriate base, it is not surprising that the fiscal devices introduced do not efficiently perform their allotted task.

In brief, economic rents from petroleum exploitation are the returns accruing to investors over and above those necessary to sustain (1) ongoing production from existing fields, (2) the development of new but discovered fields, and (3) new exploration. Measurement of the rents requires knowledge of the costs of finding, developing, and operating oil fields; production profiles, oil prices, and investors' discount rates. This is a demanding list of required information and, moreover, accuracy is essential. If inaccurate measures are employed by governments, economic distortions can then arise. If a fiscal device were put in place which permitted the development of existing discoveries but inhibited new exploration, the government in question would sooner or later become aware of this, but the time and effort required to take appropriate corrective action would produce a distorting effect on the pace of exploration and would damage the investment environment.

Knowledge of finding costs is at best elusive, requiring knowledge of prospectivity (a probability measure) as well as information on actual necessary costs. It may not be immediately apparent that impediments to exploration are being introduced. The knowledge that investors are making handsome returns on existing investments may influence policy makers to such an extent that they tax away what are in effect the quasi-rents of exploration. These are returns which can be removed in the short term without apparent damage but which are necessary in the long run if a continuing exploration effort is to be sustained.

Judgement by governments of what are necessary returns to investors in turn requires knowledge of the criteria and yardsticks commonly employed in making investment decisions. Petroleum companies use a variety of criteria, including traditional yardsticks such as payback period. Discounted cash flow techniques are widely employed in this industry, and a working definition of economic rents at the time of a new field development decision is the expected net present value at the investor's discount rate. An accurate measure thus requires knowledge of the investor's discount rate or opportunity cost of capital. This will frequently vary from project to project. A well-known technique employed in the industry to deal with a highly uncertain venture is to add a risk premium to the discount rate employed.

In this study a range of discount rates was employed. This reflects the fact that different private investors may employ different rates and that some projects may be perceived to be riskier than others. Employment of a series of discount rates also enables a distinction to be made between economic rents calculated at private and at social (possibly lower) discount rates.

In making exploration decisions, investors in the petroleum business generally calculate expected monetary values (EMVs) which take into account the chances of making discoveries of different sizes and costs. Public knowledge of prospectivity in different countries is very limited and in this study a wide range of possible success rates has been employed. In many countries state oil-company participation is a component of the legislative package facing investors, and the precise participation terms can influence the exploration decision. A carried-interest obligation at the exploration phase reduces the EMV facing the investor, the extent of the reduction depending on the size of the participation stake and whether or not the state company reimburses the investor for its share of the exploration costs.

The question of who should receive economic rents has been a controversial subject in many petroleum-producing countries. In some, oil consumers have received a share of the rents through prices' being held below free-market levels. In general this constitutes a diversion of the rents and produces a non-optimal allocation of resources – the price of the product does not reflect its opportunity cost. It is generally recognized that governments can legitimately collect economic rents for the general benefit of taxpayers, but complications arise in some oil-producing countries where a federal system of government applies. In such cases it sometimes happens that subnational governments own mineral rights and have the constitutional power to tax natural resource extraction; the federal government may also have the power to tax natural resource exploitation. There is thus scope for conflict as well as the potential for fiscal inequities to emerge among different states or provinces in a country.

Fiscal and Quasi-fiscal Arrangements

This study examined the operation of the fiscal and quasi-fiscal arrangements applied to petroleum exploitation in a wide variety of countries in which petroleum exploitation is an important activity. Both advanced industrial countries and developing ones were selected, and two OPEC members – Nigeria and Indonesia – were specifically included. The countries were chosen to encompass a wide range of fiscal devices, although countries where petroleum production has been nationalized have not been included in the study – the prime objective has been to concentrate attention on the delicate relationship between private investors and governments; in countries where the industry is nationalized the focus of interest is rather different. The wide variety of fiscal devices applied to petroleum exploitation normally – but not always – includes conventional corporate income tax. However, even when the standard income tax does apply, there are often special arrangements added on to reflect the special circumstances of the industry. As far as these special arrangements are concerned, different governments have approached the problem essentially in two basic ways. The first involves the use of auctions for the award of licences or leases. The second involves the employment of special taxation measures. A third, hybrid approach can be distinguished in some developing countries: this initially involves bids by investors but is followed up by negotiations between the investor and government, frequently leading to revisions on the initial bids.

Regarding the special taxation arrangements there is a bewildering variety of details across countries, but the instruments developed over the last 15 years can essentially be categorized under five broad headings: (1) royalties and production taxes, (2) specially modified profit-related taxes, (3) modified production-sharing agreements, (4) windfall profits taxes, and (5) resource rent taxes. In some countries more than one of these five instruments is employed, in addition to conventional corporate income tax.

In most of the countries examined there have been several changes in their system over the last decade or so. Following the oil price rises in 1973-1974, governments typically instituted major increases in fiscal takes. The subsequent price rises in 1979-1980 heralded further discretionary increases in fiscal takes. The fall in oil prices over the last few years has generally led to discretionary reductions in fiscal take by governments. The changes in levels of fiscal take over the last decade have often been accompanied by significant structural changes. There is a tendency towards more profit-related systems.

In Australia there is a system incorporating conventional royalty, production levy, and income tax. In recent years a Resource Rent Tax has been proposed to replace the conventional royalty and production levy in some areas. The latter is also reduced for new field investments in other areas. The system is generally moving in a more profit-related direction.

In the North Sea in 1975 the United Kingdom and Norway instituted a system of conventional royalties, special profits-related tax, and normal corporate income tax. The level of the special profits-related tax was increased following the price rises of 1979-1980. When oil prices fell, the non-profit-related element (royalties) was removed in both countries. For new field investments the structure is now wholly profit related.

In Malaysia there is a conventional royalty, production-sharing arrangement, and income tax. Recently the production-sharing arrangements were changed to permit earlier recovery of costs. The change represents a (modest) move towards a system geared to profitability, though in this case the scheme is still not closely related to profits.

In China the system incorporates a royalty, production-sharing scheme, and income tax. In recent years, when both the price of oil and perceived prospectivity fell, the burden was reduced by lowering the royalty.

In Egypt and Nigeria, recent changes are also consistent with moves towards a profit-related base though the scheme remains mixed in Nigeria.

In the United States the use of sliding-scale royalty schemes spread in the 1970s when oil prices increased. Since they fell, lower royalty levels have become more common. Some reductions in the Windfall Profits Tax have also been made.

In Canada, both Alberta and the Canada Lands, when the level of take was increased substantially under the NEP the non-profit-related elements formed a major component in the whole take. Since the oil price fall the changes to the fiscal system have both reduced the level of take and made the scheme more profit related.

While the tendency for the structure of fiscal systems to become more profit related can thus be discerned, the structure of the schemes in some countries still contains significant production-related elements. The indications are, however, that when a perceived need for changes in the level of take arises, governments are becoming increasingly prepared to make the adjustment by reducing the production-related component.

Effects of Fiscal Devices

Fiscal devices may be judged by various criteria. The economic distortions that may be produced constitute one obvious criterion. Thus, if exploration, new field developments, or production are impaired by fiscal devices, considerable distortions have clearly been introduced. In the present context fiscal systems can be judged by the accuracy with which they collect the economic rents. Clearly, the more directly a mechanism is related to the target of economic rents the less likely are distortions to be produced; the more closely the fiscal mechanism is related to the economic rents the higher can be the level of take without introducing distortions.

A scheme that is regressive in relation to changes in rents is both inequitable and likely to produce economic distortions. Such a scheme would collect a higher share of the rents the lower these rents became, as profits fell due to either higher costs or lower oil prices. A system that collected a given proportional share of the rents as oil prices or costs changed would not result in economic distortions and it could be said to be equitable as well.

A progressive system, which collects a higher share of the rents the higher the rents become (either from rising oil prices or lower costs), is also arguably an equitable system. It is likely to be efficient in the sense that it would not reduce incentives to explore or develop new fields. Depending on how progressive the system is, however, it could introduce a different type of economic distortion, namely, an incentive to engage in "gold-plating"-type expenditure, whereby the investor becomes better off by increasing his expenditure because the consequent reduction in his tax bill exceeds the value of the incremental expenditure. As long as this incentive is not introduced, a progressive system can be both equitable and economically efficient.

In sum, fiscal systems can be judged by how accurately they relate to the economic rents being earned and by the economic distortions which they produce.

Auction schemes, normally in the form of bonus bids, have been commonly employed in the United States and Canada as devices to collect economic rents. In favour of auctions governments do not require information on all the factors determining the profitability of petroleum exploitation. The investors make their own estimates and, under a system of competitive bidding, the surpluses accrue to the state. Unfortunately, this mechanism operates successfully only in circumstances which may not prevail in practice. In particular, the degree of competition for acreage may not be sufficient to ensure that the state obtains the expected rents. This situation may pertain in some developing countries.

Even when competition for acreage is healthy, the bidding system can only be expected to extract *ex ante* or anticipated economic rents. Over the last 15 years the price of oil has exhibited dramatic upward and downward movements which were not anticipated by investors. In the 1970s and early 1980s large windfall gains were made as a result of the huge price increases in 1973-1974 and 1979-1980. Governments all over the world felt that they had a right to share in these gains and instituted various types of special taxation in pursuit of this objective. It is noteworthy that bonus bids are regressive elements when viewed from an *ex post* perspective. The more prolific the discovery turns out to be, the smaller will be the bonus bid as a proportion of the net present value from this field.

Production taxes and conventional royalties are clearly not well related to economic rents, being based on production revenues rather than on profits. Payments commence from the first day of production and there is no allowance for return on capital investment. Depending on the size of the imposition, economic distortions – such as premature abandonment of fields and non-development of new fields – could result. Both production taxes and royalties are regressive in their relationship to economic rents.

Corporate income taxes are not normally directly geared to economic rents, and whether they are proportional or regressive in their relationship to economic rents depends critically on the speed with which investments can be recovered. The slower the permitted pace the more likely that the income-tax yield will be regressive in its relationship with economic rents. How close the link is also depends on whether allowed depreciation starts with the expenditure or when the asset is placed in service. A cash-flow type of corporation tax with full loss offsetting would be proportionally linked to economic rents.

The special profits-related type of tax introduced by the United Kingdom and Norway (and other North Sea producing countries) is related indirectly to economic rents. Possible economic distortions are not readily apparent. The link is definitely an indirect one, however, and the rate of special tax and the "uplift" on capital expenditure – the main mechanisms for relating the payments to economic rents – are found to be insufficiently sensitive to major changes in the rents to prevent distortions from emerging. The fact that the rates of tax are very high increases these dangers.

Special excise taxes – such as the Windfall Profits Tax in the United States, the Excess Proceeds Tax in Malaysia, and some features of the royalty formula in Alberta – are clearly more sensitive to changes in the operating environment than are conventional royalties. But the mechanisms are not directly related to economic rents; where major changes in oil prices or costs occur, it is likely that discretionary changes to the schemes will be required to prevent distortions emerging.

Progressive production-sharing arrangements are common in Third World countries. They can readily cater for major differences in field sizes, but they cannot respond appropriately to large changes in oil prices. A given scheme may efficiently collect economic rents at one level of prices but introduce major disincentives at a much lower oil price level. Production-sharing schemes are not directly targeted on economic rents.

Resource rent taxes are generally favoured by economists because the levy is directly targeted on economic rents. If the rents change – either through a fall or rise in oil prices or a major change in costs – the tax payments automatically adjust to prevent economic distortions arising. In practice, efficiency demands that the investor's cost of capital be known with some accuracy, as distortions could arise if the government underestimated the cost of capital. Under a resource rent tax incorporating more than one tier there is also a danger that "gold-plating"-type incentives could emerge.

Results of Empirical Analysis

With the aid of a set of computerized financial models and a suite of model fields, the effects of the fiscal systems in a number of jurisdictions were simulated under oil price perspectives of 1985 and 1986-1987. The simulations were undertaken at two decision times, namely, those relating to new field developments and to exploration. The results were calculated for different discount rates.

A main conclusion of this study is that the great majority of the fiscal systems do not perform very efficiently as extractors of economic rents. The Resource Rent Tax scheme in Australia performs better than many others, though the inclusion of the normal income tax can mean that in principle disincentives could emerge. The high threshold rate also means that significant rents may remain with investors. The other main fiscal system in Australia provides a stark contrast—the performance of the scheme incorporating the conventional royalty and production levy is such that it is highly regressive in its relation to economic rents, and there are distinct possibilities of disincentives emerging under conditions of high costs or low oil prices. This system is not at all well related to economic rents in its structure because of the sizeable production-based components. On marginally attractive fields such systems do not make government share in investment risks with investors as compensation for the high effective burden.

In the United Kingdom the fiscal system applied to petroleum exploitation is now wholly profit related for new fields. This scheme performs more satisfactorily than many others in the study, often taking a high share of rents when they are large and a much smaller share when they are small. Policy makers have attempted to relate the take to the rents. The link is via a modified special profits-related tax. While the scheme works moderately well, it is still inherently insufficiently flexible to cater automatically for the wide range of operating conditions likely to obtain. The reasonable performance of the U.K. system has also been brought about at the cost of great complexity. It is likely that the need for some discretionary modifications will continue as the operating environment changes.

The Norwegian system applied to new fields is also wholly profit related. The average take in this country continues to be very high, while the system's flexibility to changes in the operating environment remains modest. The system is related to profits but not to profitability; it is thus not directly linked to economic rents. There is a danger that it does not take sufficient account of differences in unit cost conditions across fields and, given the high level of take, disincentives could still emerge. The limited automatic flexibility probably means that discretionary changes will be required to be made as the operating environment changes.

In Indonesia there is a production-sharing system with income tax. The system is profit related but not directly linked to economic rents as seen by investors. The level of take is high and there is not much inherent flexibility in the correct directions in response to changes in the operating environment. If exploration were to take place in deeper waters or oil prices were to fall again, discretionary changes would have to be made to prevent significant economic distortions from emerging.

In Malaysia the system is complex, incorporating a royalty, production-sharing scheme, and income tax. The level of take is very high and the scheme is regressive in its relationship to economic rents. There is a distinct lack of flexibility in the appropriate directions. In particular, if exploitation were to take place in deeper waters or oil prices were to fall again, economic distortions would readily be produced. The system performs its function effectively only within a narrow range of oil prices and costs. There is thus a likelihood that discretionary changes will have to be made when operating environment shows significant changes.

In China the system incorporates a royalty, progressive production-sharing arrangement and income tax. The system produced is regressive, with the take at moderate levels under low cost conditions for moderate sizes of fields. The scheme is not well related to economic rents. Consequently, it is inherently inflexible in response to major changes in the operating environment, particularly those due to big oil price changes. The system produces a comparatively modest level of take on the smaller, low-cost fields. If these fields dominate, then perhaps no economic distortions will be produced. But the result has been produced by a scheme which is not accurately collecting the rents. A scheme which was more closely related to the rents could perform more efficiently from an economic viewpoint and possibly collect a higher share of the rents.

In Egypt there is a production-sharing scheme which is profit related but not directly linked to economic rents as measured by investors. The level of take is high, and the scheme is inherently not very flexible in response to changes in the operating environment. To avoid distortions, changes would need to be made to the terms if oil prices or costs changed by significant amounts.

In Nigeria the system incorporates a royalty and special profits-related tax. The level of take is very high and, in addition, the system has not been inherently very flexible to changes in the operating environment. It is not directly linked to economic rents. In response to the recent falls in oil prices, complex rules have been instituted to reduce the effective profits tax to avoid economic distortions. The resulting scheme is more complex but is still not well related to economic rents. Further discretionary changes will be required in response to significant changes in the operating environment.

In the U.S. Outer Continental Shelf there is a system of bonus bids, royalty, federal income tax, and Windfall Profits Tax. The scheme is regressively related to economic rents. The tax component in the overall take is comparatively low on the most likely field situations and this prevents distortions from emerging. Though the royalty and tax system could introduce disincentives in deepwater circumstances under low oil prices, the extent to which this is likely to happen is less than in other jurisdictions.

In Alaska there is a royalty, production tax, state income tax, and federal income tax, as well as a bonus bidding system. The tax components of the whole scheme produce a high level of take and a system which is regressive in its relationship to economic rents. The tax system is not very flexible in response to changes in the operating environment. The very high level of take is sustained by the high prospectivity, but discretionary changes in the system will be required if unit exploitation costs increase or if oil prices continue at low levels.

In Texas the fiscal system includes local property tax, state production tax, federal income tax, and Windfall Profits Tax. Royalties are generally payable to private landlords. On reasonably profitable fields the tax take is not especially onerous; only on marginal fields would disincentives be produced. The property-tax element is well directed at economic rents, though the other components are not.

Under the fiscal system in Alberta the provincial royalty is a dominant ingredient under the pre-NEP, NEP, and post-NEP schemes. The royalty formula makes royalties payable a function of well production volumes, oil prices, and the time of discovery. There are some elements of progressiveness built into the overall scheme – the royalty tax credit, royalty rebates, and royalty holidays help to reduce the potential regressiveness of the scheme in present-value terms, as these reliefs are generally available early in a field's life. Combined with front-end reliefs for an ongoing investor, the overall system in pre-NEP and post-NEP circumstances becomes one which is only very mildly regressive over the most likely cost conditions. Under higher cost conditions the system becomes more noticeably regressive, however. The royalty formula and the many associated reliefs and allowances have some inherent flexibility in the required direction but not sufficient to cater automatically for a very wide range of operating circumstances. For these reasons there is likely to be a continuing requirement for discretionary changes in response to major changes in the operating environment.

Under the post-NEP system in Alberta, where royalty holidays are very significant, the tax take is often very moderate on the most likely field situations. The effectiveness of the whole system in collecting economic rents depends on how efficiently the bonus-bidding system operates. It could be argued, however, that if the whole taxation component has been more directly targeted on economic rents it could have more readily collected the rents without introducing the possibility of disincentives in more marginal field situations.

A noteworthy feature of the whole scheme applied to Alberta, with its proliferation of deductions and allowances, is its great complexity. The allowances may be required to ensure that the basic structure does not produce economic distortions, but the cost is the additional complexity. The compliance costs are higher as a result.

The exploration incentives may well work, but it is probable that a scheme which was more directly linked to economic rents could meet all the required objectives with less complexity and frequency of discretionary changes.

Under the NEP the fiscal system in Alberta included the Petroleum and Gas Revenue Tax (PGRT). This was not a crude production tax but it was still not well related to economic rents. Consequently, the overall system was not well linked to rents. The system of Petroleum Incentives Program (PIP) benefits helped to prevent serious distortions from emerging. The introduction of the PIP grants is characteristic of the checks and balances which have played a significant role in the petroleum fiscal mechanisms in Canada for some years. As noted above, it can be argued that a more efficient result, with lower compliance costs, could be achieved by a simpler scheme more directly targeted on economic rents.

In the Canada Lands the Progressive Incremental Royalty (PIR) on its own generally performed in a reasonably efficient manner. When it was combined with the conventional royalty, however, economic distortions could be produced in situations where exploitation was not very profitable. When the PGRT was added as well, the chances of economic distortions emerging were significantly increased. The PGRT instrument was not sensitive enough to major changes in the operating environment to prevent disincentives from emerging.

The post-NEP system on the Canada Lands is much more sensitive to changes in the operating environment than the NEP one. The range of conditions that are included in the Canada Lands, however, is very great. There are enormous differences in the field sizes and costs in the different geographic locations. The only significant fiscal device which is differentiated geographically appears to be the investment tax credit. This provides a worthwhile incentive for projects with very high front-end costs and influences the size of the tax take in present-value terms. A complex system of taxes and allowances, the post-NEP scheme is regressive in onshore situations: where the fields are marginal, disincentives could emerge. As in Alberta, the system of incentives for exploration operates strongly in the post-NEP situation. Canada has stronger exploration incentives than most petroleum-producing countries.

The fiscal systems examined share the risks of petroleum exploitation between investor and governments in ways which essentially depend on the structure of the mechanisms. Systems that are heavily based on production leave the bulk of the risks with investors. Systems that are wholly profit related and that permit new exploration and development costs to be set off against income from other projects entail government acceptance of a much higher share of the risks. Systems that incorporate a large production-based component were often found to be likely to cause economic distortions. In addition the investor has to bear more of the risks. The possibility of a trade-off should exist here. A fiscal system that entailed the acceptance of a high share of the risks by the host government should imply that the government should be able to collect a higher share of the economic rents.

Conclusions

The main finding of this study is that the fiscal and quasi-fiscal devices in existence in many petroleum-producing countries do not collect the economic rents from petroleum exploitation in a very efficient manner. The instruments employed are frequently not directly targeted on economic rents, and it follows that the rents cannot be efficiently collected. There is likely to be a lack of accuracy and economic distortions may well arise, leading to a need for discretionary changes. This need is increased if the operating environment is subject to large changes. Fiscal mechanisms that are directly targeted on economic rents will more effectively collect economic rents, reduce the need for discretionary intervention by governments, and improve the investment climate to the advantage of all.

A combination of bonus bids with a resource rent tax offers the best hope for the accurate collection of economic rents without introducing distortions. The bonus bids can extract *ex ante* rents and provide governments or other resource owners with an early cash flow from the provision of mineral rights to investors. The resource rent tax can collect *ex post* economic rents and provide a cash flow to governments in subsequent years.

The proper design of a resource rent tax raises several complex technical issues. If the threshold rate is not accurately specified, the rents will be inaccurately measured, with dangers of either undercollection of rents or disincentives emerging. Governments have a strong preference for stability of revenues over time. This is generally not possible with petroleum exploitation, but devices such as advance resource rent payments—starting with initial production and subsequently creditable against the resource rent tax liabilities—can help to spread the flow of revenues more evenly. The use of the device of advance Petroleum Revenue Tax in the United Kingdom, where the early production-based payments were credited against later Petroleum Revenue Tax, is an example of this type of scheme.

Postscript: Canadian Policy Perspectives

by Campbell Watkins

The purpose of this postscript chapter is to focus on the lessons for Canadian oil policy of the preceding comprehensive analysis and comparisons undertaken by Alexander Kemp.

The chapter begins by emphasizing the imprecision surrounding any empirical assessment of what at first glance seems to be the quite straightforward concept of economic rent, and by commenting on the implications this has for fiscal policy. Next, some of the salient features of efficient rent acquisition systems are discussed. Then the light that Kemp's study sheds on the nature of Canadian fiscal regimes is summarized. Concluding remarks are made on international comparisons and current problems.

Economic Rents

Identification and Appropriation

An array of Canadian fiscal and other policy instruments have determined net revenues of the petroleum industry. These measures include: gross royalties or taxes based on output volumes or values; bidding for exploration, development, and production rights; net royalties or profit taxes allowing for actual or imputed costs; corporation income taxes and related special exemptions and provisions; equity participation by governments; property taxes; regulated prices; and export controls.[1] In terms of appropriating economic rents, the most relevant instruments are royalties, bids, income taxes, equity participation, and regulated prices.

Since a petroleum reservoir produces over several periods, economic rent can be couched in terms of the difference between present-value revenues and present-value costs, where the discount rate is the cost of capital. Because rents by definition are an excess return, ostensibly they could be taxed away without affecting the pace or level of industry activity. However, because rent extraction would reduce industry profitability and cash flows, inevitably it will influence the rate of investment. Moreover, it is seldom that rent can be appropriated without introducing some inefficiencies or distortions.

At the least, rent acquisition should be neutral in the sense of being so calibrated that project rankings are unaffected and the return on the marginal investment left unimpaired.* These criteria offer a tool for assessing the efficiency of resource-taxation regimes, discussed later.

Broadly speaking, there are two methods to acquire rents: a single, up-front payment; or a stream of payments over the production period. The latter could also take the form of periodic payments set to equate with present-value rents. These mechanisms are not exclusive. A useful distinction can be made between rents arising from variations in "quality" – a common phenomenon with extractive resources – and those arising from expected (*ex ante*) and realized (*ex post*) variations in prices (and costs).

Up-front single-payment bids on development and production rights can normally capture "quality"-type rents as long as knowledge about the biddable prospects is well established and competition is sufficiently genuine and intense. Under such conditions bonus bids tend to be the least distortionary and least avoidable of mechanisms. However, bids cannot handle rents associated with unanticipated prices (and costs). And in the case of oil it is differences between realized and expected prices that have dominated rent generation (or attrition) over the past decade or more. Hence the importance of flow-type mechanisms – for example, royalties – as a rent-collection device. Moreover, flow mechanisms are better tailored to the need governments have for some degree of stability in revenues over time.

Under bidding mechanisms, although the award of rights can be at the discretion of the disburser, identification of rent is essentially (like beauty) in the eye of the beholder, in this case the bidder.

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* A nuance in the context of stock-type resources is whether the costs used to determine rents should include user costs – profits forgone by producing now rather than later. In the absence of an allowance for such opportunity costs, rent appropriation may well affect the timing of optimal production. Note that cross elasticities of supply over time favour some degree of permanency in tax measures.

However, mechanisms which require the collector to have a good feel for rents entail precise information on relevant costs. In the case of petroleum, reservoir development and extraction costs can be readily calculated. But what of finding costs? These are seldom reservoir-specific but must be defrayed in the long run. Recovery of finding costs would matter little if they were trivial. However, a simple calculation shows this is not the case: over the period 1975 to 1985 exploration expenditures accounted for 47 per cent of total upstream expenditures (excluding taxes and royalties) made by the Canadian petroleum industry.[2]

Thus, while economic rents at the stage of reservoir exploitation can be estimated with reasonable precision, they represent only quasi-rents. If all such quasi-rents were taxed away, the process of resource replenishment by new discoveries and by enhanced recovery from existing discoveries would be terminated.

Finding costs, then, introduce a distinction between short-run, or quasi, rents and long-run, or full-cycle, rents. Since finding costs are not reservoir-specific, it follows that long-run rents associated with individual deposits are inevitably imprecise and uncertain.[3] And it is long-run rents on which public policy should focus. Full appropriation of short-run rents would only kill the goose that lays the (black) golden eggs.

Quite apart from the distinction between short-run (quasi) and long-run (full) rents, should public policy deliberately seek to extract the maximum amount of rent?[4] There are several reasons why adoption of such a severe objective should be avoided.

First, maximum rent extraction would make exploiters largely indifferent between high- and low-cost deposits, within the band of economically developable supplies. This would not provide an efficient operational climate. Techniques to extract all rent would be tantamount to a cost-of-service regime. One of the problems of cost-of-service with which regulators grapple is how to preserve some rewards for productivity.

Second, a maximum policy would leave little margin for error. Any allowance which sought to defray exploration costs might be swiftly overtaken by events. It is always difficult to unravel rents from required profit levels; required minimum profits (cost of capital) remain more a range than a precise number. The exactitude of the information required on cost structures by deposit is often difficult to obtain. Thus, many measures aimed at pure rents end up by taxing quasi-rents.

Third, the existence of substantial economic rents – particularly "qualitative" rents – is normally associated with significantly rising costs of incremental supplies. Firms seeking to operate as going concerns will wish to replenish reserve stocks, but the cost becomes progressively higher (increasing replacement cost). This might be of little consequence if funds for exploration and development were easily obtainable. However, capital markets are imperfect. Leaving some rent in the hands of resource exploiters therefore could offset capital market distortions and would be consistent with the traditional degree of reliance placed by upstream oil activities on internal cash generation.*

These considerations suggest that governments should adopt the more modest aim of obtaining a preponderance of, rather than all, the apparent and uncertain long-run economic rent. What would constitute a suitable proportion is difficult to specify, but adopting a criterion of, say, two thirds to three quarters would leave scope for efficiency incentives, allow a margin for error, and provide a source of funds for resource companies. It may lead also to higher eventual long-term government revenues. This is important and should not be thwarted by attempts to maximize inflows from one component of several sources of public revenues. Policy objectives on rent acquisition may also be constrained by competition among jurisdictions. And where more than one jurisdiction is involved within a region, avoidance of too severe a rent bite will lessen the danger of overlapping claims.

In short, because identification of economic rents in the oil production sector can never be more than approximate, any intent to capture them should be supple rather than relentless.

Efficiency of Capture

Suppose the notion is accepted that as owners – and for other reasons – governments should seek to garner the predominance rather than the entirety of economic rents. What should be the characteristics of an efficient rent-collecting regime, where efficiency connotes the avoidance of distorted investment and production decisions?

If a regime applying to a multitude of conventional oil reservoirs is to be something other than a compendium of *ad hoc* deals, then it certainly must incorporate sensitivity to different levels of reservoir operating and development costs and leave a sufficient wedge to compensate for unassignable exploration costs. The latter can be handled in a general way by the decision to appropriate only a suitable share. Moreover, the regime must accommodate changing levels of prices.

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* The upstream debt/equity ratio is relatively low in the petroleum industry, suggesting correspondingly high risks. Note that capital market imperfections could be addressed by measures other than rent retention.

Any enduring regime should be sensitive to these two dimensions – costs and prices – which potentially cover a very wide combination of outcomes. Just in terms of one jurisdiction considered in this book, the estimated quasi-rents (before allowance for exploration costs) vary by a factor in excess of twenty between the high price/low cost and low price/high cost cases.[5] And notwithstanding the best efforts of forecasters (sorcerers?), price projections cannot but straddle a range, while likely cost levels cannot be estimated with precision. This degree of uncertainty suggests that a single instrument for rent collection is unlikely to suffice. Indeed, if an all-embracing measure equivalent to a sort of (economic) philosopher's stone existed, no doubt it would have been unearthed by now.

It was argued earlier that there were two key features of rents in the context of natural resources – rents may be associated with variations in quality or they may be associated with unanticipated variations in net revenues. The former could be handled by some kind of "stock" levy such as bonus bids; the latter suggests the need for some kind of "flow" payment such as royalties or profit-related taxes. A comprehensive system may well combine both types of instruments.

The key to the efficient operation of a tax regime remains the preservation of return on the marginal investment to ensure economic exploitation of the full range of reservoirs. In the jargon, as long as a reservoir's *social* return were positive, exploitation would be socially desirable. Stock-type payments (such as bids) satisfy this criterion: no company would knowingly formulate a bid that would impair its ability to exploit a deposit. But flow-type payments (such as royalties) that are not in some measure profit sensitive could either discourage reservoir development (especially in high-cost cases) or induce premature abandonment of wells.

Also, given different types of reservoirs and different levels of prices, it is desirable for rent-collecting regimes to be consistent in the sense of yielding compatible rent shares.[6] The proportion of rent paid by a high-cost reservoir should at least be the same as or lower than that paid by a low-cost deposit; the proportion of rent payable when prices are low should be no more than when prices are high. Such consistency can be thought of as "horizontal equity."

This criterion suggests an easy way to interpret the graphs of government rent shares versus varying cost and price levels plotted in Chapter 6. Suppose the initial share of rent obtained from a reference reservoir were viewed as reasonable from a public policy standpoint – certainly not exceeding 100 per cent and varying in the range of 50 to, say, 75 per cent according to whether bonus bids or other up-front payments were made. Then ideally the curves for various cost levels and pricing outlooks should be flat and coincident: government rent *shares* would be unaffected by prices and costs. It also follows that if these shares *do* vary according to the key price and cost elements; this would be regressive. On the other hand, as Kemp mentions, a system which collected a higher share of rents as rents rose could be viewed as equitable, in the spirit of progressive taxation.

Government shares of quasi-rents (rents before allowance for finding costs) should be smaller the poorer the deposit. This is because finding costs do not vary directly as a function of reservoir size. Compensation for the fixed portion of exploration costs suggests smaller reservoirs should retain a higher share of quasi-rents, although of course such costs cannot be allocated definitively.

Perhaps the fiscal device about which economists are most likely to wax lyrical as representing the best attempt to tax pure rents is the Australian Resource Rent Tax (RRT).* The results of this study suggest that, at least for low to medium cost thresholds and for various price trajectories, the government rent shares under the RRT are robust. It is only with higher cost levels, higher discount rates, and falling prices that distortions appear, and these seem to be attributable more to income-tax structures than to the RRT itself (see Figures 6.9 and 6.10, with commentary). Yet acceptance of the RRT is less than enthusiastic. Practical defects include the (uncertain) attribution of costs and revenues to projects, problems with threshold rates for the compounding of up-front investments, what RRT rate to set, provisions for transfer of tax liabilities and losses, and administrative costs. It has been suggested that the RRT as currently applied in Australia has the undesirable characteristics of implicitly taxing risky exploration, implicitly subsidizing overinvestment in development, and retarding extraction.[7]

Canadian Regimes: Efficiency Characteristics

Kemp's analysis provides two sets of results for Canada – Alberta and Canada Lands – and the Alberta and Canada lands schemes are examined under three tax regimes – pre-National Energy Program (NEP); NEP (late version); and post-NEP (Western Accord and Canada Lands revisions). Also, the analysis is conducted for three sizes of reservoir, each at several levels of development costs and four sets of prices (increasing, constant, and declining real, and "collapsed"). For the NEP cases, results are shown both with and without Petroleum Incentive Program (PIP) grants and, where relevant, with and without government participation. The rents, and the estimated government shares of them, relate to quasi-rents: costs are confined to the development and extraction phases. The impact of exploration costs is pursued separately.

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* In essence, the RRT is levied on project cash flows before income tax but after a specified return has been achieved on investment. This is accommodated by accumulating any excess expenditures over receipts at a "threshold" rate. These are "paid out" before levy of the RRT; see Chapter 3.

Alberta *

The first and most striking feature of the Alberta results is that structurally the various regimes are reasonably consistent and efficient, especially for the more likely range of costs, and especially in comparison with typical outcomes for overseas jurisdictions. This can be seen by a quick scan of the series of Figures 6.54 to 6.65, showing government shares of estimated economic rents. By and large, for each regime the curves are relatively flat for given reservoir sizes as costs increase, at least before costs start to reach high levels, and are quite coincident for different price trajectories. Moreover, the level of government take falls as reservoir size decreases – a desirable outcome if the retained margin is seen as defraying relatively fixed exploration costs. However, it is noteworthy that the government take becomes more regressive for all tax regimes in the case of the collapsed oil price. Under the NEP regime, the availability of PIP is important in attenuating regressivity.

The reasons for these results, which are discussed in Chapter 6 are not repeated here. Suffice it to say that the results reflect quite extensive adjustments, suggesting that the basic fiscal frameworks are not as robust and sensitive as they seem.[8]

What is also significant is the continued existence of lease bids on crown lands under the various regimes. This confirms the availability of additional rent to be garnered by the public purse since, except for fly-by-nighters, bidders recognize the need to cover long-run exploration costs in bid formulation. In other words, in broad terms the fiscal frameworks were not punitive under prevailing price expectations even after recognition of the need to compensate for finding costs.

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* In broad terms, the pre-NEP system featured: royalties distinguishing between "old" and "new" oil, with both price- and volume-sensitive components; federal income tax incorporating many allowances and deductions, but without deductibility of royalties; an allowance to compensate for disallowance of royalty deductions; depletion allowances; and Alberta income tax structurally similar to federal imposts but providing various royalty tax rebates and royalty tax credits. Moreover, the price at which Alberta oil was sold was held below world oil price equivalence. The (later version) NEP included the federal Petroleum and Gas Revenue Tax (PGRT), levied in essence on production revenues less operating costs; depletion allowances were replaced by exploration and development cost subsidies (PIP grants). World oil prices applied to new oil. Under the post-NEP regime, PGRT and PIP grants were eliminated, Alberta royalties were lowered, and further royalty credits were granted. The results do not include the March 1987 Canadian Exploration and Development Incentives Program (CEDIP). For details, see Chapter 3.

The shift in government rent shares over the three fiscal regimes examined is brought together in Table 8.1. The numbers shown are for the medium cost/constant real oil price case, for two sizes of reservoir. The results discussed focus on a 10 per cent real (after tax) discount rate; some support for using a rate in the region of 10 per cent is provided by estimates which have the real cost of equity capital for the Canadian oil and gas production sector at 11 to 13 per cent.[9]

Table 8.1
Alberta
Comparison of Government Takes under Various Tax Regimes (percentage of present-value rents) [a]

Recipient of Rents	Smaller Reservoir				Larger Reservoir			
	Pre-NEP	NEP		Post-NEP	Pre-NEP	NEP		Post-NEP
		With PIP	No PIP			With PIP	No PIP	
Alberta Gov.	34	35	37	26	40	42	45	38
Federal Gov.	24	45	44	25	24	43	43	25
Consumers	8	-	-	-	7	-	-	-
Total Rents Collected	66	80	81	51	71	85	88	63

Source: Figures 6.54, 6.60, and 6.65 (Chapter 6 above).

Notes: Dash (-) indicates zero.

a. Assumes constant real prices of $27/bbl (US$), a real discount rate of 10 per cent, and medium development costs.

For both sizes of reservoir the table clearly shows the dramatic shift in rent shares towards the federal government under the NEP (in excess of 40 per cent) compared with the pre-NEP situation (24 per cent). Moreover, the NEP version used here is not the original NEP of October 1980 but rather the regime in existence after the 1981 Edmonton-Ottawa agreement of September 1981. The numbers in the table are consistent with the notion that Alberta did not fare too well in negotiations with the federal government.[10]

It seems that Alberta acquiesced in a new and substantial taxing role by the federal government in return for higher wellhead prices, while incurring some new financial obligations. Both levels of government benefited from the mandated increase in oil and gas prices over levels set in the October 1980 NEP, at the expense of Canadian consumers.[11]

The Western Accord – which deregulated oil prices, later eliminated federal "royalties" (PGRT) and cost subsidies (PIP grants), and included further adjustments (mainly royalties) partly induced by collapsing prices – put the federal government *rent* shares almost precisely back to where they had been under the pre-NEP regime, while the Alberta government shares were reduced, particularly for smaller reservoirs. The latter probably reflects front-end royalty relief. (In order to make this comparison between the pre-NEP and post-NEP cases, the rent share going to consumers by virtue of price controls under the pre-NEP regime is excluded.)

How well do these fiscal regimes adapt to the collapsed oil price – the case that best approximates current circumstances? Under pre-NEP the (combined) government share of sharply reduced rents is some 70 per cent for the larger reservoir and just over 60 per cent for the smaller deposit. Under the NEP the respective takes are substantially higher, at some 87 per cent and 82 per cent. Post-NEP (Western Accord) there is a marked reduction in government take; for the larger reservoir it is some 63 per cent, for the smaller reservoir, 50 per cent.[12]

A comparison of these aggregate government shares with the corresponding shares in Table 8.1 shows little variation. In other words, it would seem that superimposing the collapsed-price case on the various charts plotting government rent shares against costs for the cases of constant, rising, and falling real oil prices would simply provide another quite coincident line. Thus, government shares under any one fiscal regime appear relatively invariant to all the price cases considered, although of course the shares differ between fiscal regimes.

And since government takes under the post-NEP regime are the most lenient, does this mean that, quite apart from the sharp reduction in cash flow from which the industry is suffering, incentives to develop new supply are being preserved as well as might be expected at present prices? The answer depends on the magnitude and nature of finding costs, because the calculated rents do not reflect allowance for the after-tax cost of exploration inputs.

Conventional exploration inputs comprise geological and geophysical work and the drilling of both dry and successful exploratory wells. As discussed previously, such costs are seldom reservoir-specific, but over an entire investment cycle a company must both cover and earn a return on them. While it is not feasible to allocate exploration inputs to individual reservoirs definitively, some insight can be gleaned by allowing for them on an average basis, as Kemp did in Chapter 6.

As outlined in Chapter 5, Kemp's allowance for exploration costs went through the following steps: a likely distribution of field sizes in nature was calculated, using size distribution probabilities; a further weighting was made for the overall probability of making a discovery; finally, exploration costs were deducted. The resulting values, called Expected Monetary Values (EMVs), were calculated both before and after tax. This procedure was undertaken for various discount rates, various sizes of exploration programs, various success rates, and two pricing outlooks (constant real and collapsed).[13]

The flavour of the results for the three different tax regimes is summarized in Table 8.2, which assumes a 10 per cent discount rate, a discovery rate of 1 in 10, and a $5 million exploration program; tax takes as a percentage of pre-tax EMVs are in brackets. The pre-tax returns (not shown) were positive in all cases examined, indicating that exploitation of the reservoirs would be socially desirable.

Table 8.2
Alberta
Expected Monetary Values at Exploration Stage
(net present values in millions of US$ 1985)

World Oil Price	Pre-NEP	NEP		Post-NEP
		No PIP	Max. PIP	
Constant Real Price	1.2 (74.7%)	-0.4 (105%)	1.0 (91.4%)	2.3 (74.3%)
Collapsed Price	-0.5 (120%)	-1.5 (149.1%)	-0.3 (111.1%)	0.0 (100.8%)

Source: Tables 6.16, 6.17, 6.18, 6.19, 6.20, and 6.21 (Chapter 6 above).

At a constant real oil price equivalent to US$27/bbl, the post-NEP regime is more attractive for the investor than both the pre-NEP and NEP impositions; returns from the latter are heavily dependent on the availability of PIP. Indeed, at US$27/bbl oil exploration under post-NEP is almost profitable at as low a success rate as 1 in 20 (see Table 6.20). This helps to explain the revival in Alberta exploration activity and plans in 1985, before the trauma of plummeting oil prices in 1986. Note that the government take post-NEP in the case of constant real oil price reverts to much the same level as pre-NEP.

Table 8.2 also shows the pre-NEP and NEP regimes as being unable to handle collapsed oil prices, while under post-NEP exploration would be no more than a break-even proposition.[14] Moreover, if "prospectivity" (chance of success) declined as part of the normal process of resource depletion, then the combination of the current tax regime and collapsed prices will eliminate exploration for higher risk prospects, even though pre-tax returns (social returns) might remain positive (see Table 6.21).

The policy implication is for some further retrenchment of government takes—and in particular of provincial royalties, given elimination of the PGRT—to sustain the exploration and development of prospects offering positive social returns. It is noteworthy, however, that the calculations exclude the impact of the federal government's March 1987 CEDIP measures, which provide sustenance.

The impact of the PGRT can be evaluated by looking at the difference between post-tax EMVs under the NEP with no PIP grants and under the post-NEP regime. The former results in a loss of $1.5 million[15] in comparison with a break-even position post-NEP. The indicated leverage of the PGRT or the bottom line is quite strong, as would be expected with any impost so strongly related to gross revenue. The comparison is also affected by the presence of post-NEP royalty holidays.

Canada Lands *

With regard to government shares of rent, straightforward comparisons between Alberta and Canada Lands are bedevilled by the presence of additional government revenues from bonus bids in Alberta. Thus, comparisons of government takes in these jurisdictions relate more to the direction of responses to changing economic conditions than to absolute levels.

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* The pre-NEP Canada Lands fiscal regime was a basic royalty plus a Progressive Incremental Royalty (PIR); a tax on imputed field profitability. Petro-Canada also enjoyed participation rights in permits. The NEP regime kept the basic royalty and PIR, and gave Petro-Canada a 25 per cent interest in every petroleum right; PIP grants were set at higher levels than for provincial lands; depletion allowances were phased out. The post-NEP system eliminated Petro-Canada's participation rights, the basic royalty, and the PIR. A new royalty system involves low rates until project payout is achieved; royalty credits are awarded on the basis of exploration costs, as are exploration tax credits. For details, see Chapter 3. For discussion of reasons for the results achieved, see Chapter 6.

The Canada Lands analysis in Kemp's study distinguishes between the Mackenzie Delta (onshore), Beaufort Sea, and the Atlantic East Coast. The results are summarized in Figures 6.69, 6.73, and 6.75 through to 6.79. For a given fiscal regime, the differences in the results for the three regions solely reflect variations in cost configurations and sizes of deposits, with the exception that investment tax credits are not awarded to onshore activity.

Table 8.3 compares in summary form the main features of the Alberta and Canada Lands results. In virtually all cases the collapsed oil price renders Canada Lands exploitation uneconomic. As will be argued below, however, this result has little to do with fiscal regimes. None of the Alberta regimes is progressive with respect to cost changes. By way of contrast, in a few instances Canada Lands yield progressive patterns. Note that Canada Lands under the NEP and the pre-NEP regimes veer to "neutrality" (constant government rent shares) in the case when (real) prices rise steadily; this suggests that the design of these regimes was influenced by price perceptions held at the time they were devised.

The trend in the government share of rents on Canada Lands (excluding exploration costs) under different fiscal regimes is shown in Table 8.4 for the constant oil price/medium development cost case, at a real discount rate of 10 per cent; similar relationships between the regimes hold for different price/cost configurations. The post-NEP regime is generally more lenient than any of its predecessors, and is progressive in generally extracting a lower government rent share as the quality of reservoirs deteriorates and as prices decline.

Prospects at the exploration stage for the post-NEP system are brought together in Table 8.5 for a 1 in 5 discovery rate and 10 per cent real discount rate. Comparisons of absolute figures between Table 8.5 (Canada Lands) and Table 8.2 (Alberta) should be resisted, since the magnitude of the exploration programs and the nature of the plays differ. The tax takes (shown in brackets on the table, as a percentage of pre-tax EMVs) are markedly lower for the Beaufort Sea and Atlantic Ocean than for the Mackenzie Delta. To some extent this may reflect the absence of investment tax credits for the Mackenzie Delta.

None of the Canada Lands regimes was able to handle the collapsed oil price (see Table 8.3); a minor exception was Beaufort under the NEP, but the rents were rapidly extinguished as costs increased. This situation cannot be rectified by further reductions in royalties and taxes. Rather, it simply reflects the fact that low oil prices render Canada Lands activity uneconomic, except for easy-to-discover, prolific reservoirs.

Table 8.3
Alberta and Canada Lands
Comparisons between Fiscal Regimes

	Alberta	Canada Lands		
		Mackenzie	Beaufort	Atlantic
Pre-NEP				
1985 Price Expectations[a]	Mildly regressive	Neutral for big reservoir; regressive for smaller reservoirs, except for rising prices	Neutral or mildly progressive	Regressive except for rising prices
Collapsed Prices	Regressive	Neg. rents	Neg. rents	Neg. rents
NEP				
1985 Price Expectations[a]	Regressive	Regressive except for rising prices	Neutral	Regressive except for rising prices
Collapsed Prices	Regressive	Neg. rents	Sharply Regressive	Neg. rents
Post-NEP				
1985 Price Expectations[a]	Mildly regressive	Neutral for big reservoir; regressive for smaller reservoirs	Mildly Progressive	Progressive
Collapsed Prices	Regressive	Neg. rents	Neg. rents	Neg. rents

Source: Various charts (Chapter 6 above).

Notes: "Regressive" or "progressive" generally refers to shifts in shares with respect to costs.

[a] 1985 Price Expectations refers to the set of simulations for increasing, constant, and declining real prices.

Table 8.4
Canada Lands
Comparison of Government Takes under Various Tax Regimes (percentage of present-value rents)

	Large Reservoirs	Small Reservoirs
Mackenzie Delta (Onshore)		
Pre-NEP	61	62
NEP, PIP at 20% (no gov. participation)	75	85
Post-NEP, new royalty	64	60
Beaufort Sea		
Pre-NEP	52	50
NEP, PIP at 20% (no gov. participation)	67	65
Post-NEP, new royalty	55	50
Atlantic Ocean		
Pre-NEP	68	85
NEP, PIP at 20% (no gov. participation)	75	98
Post-NEP, new royalty	55	45

Source: Various figures, Chapter 6 above. For Mackenzie Delta (Onshore), Figures 6.70, 6.71, and 6.74; for Beaufort Sea, Figures 6.81, 6.84, and 6.88; for Atlantic Ocean, Figures 6.94, 6.96, and 6.98.

Table 8.5
Canada Lands
Expected Monetary Values at Exploration Stage, Post-NEP System, Constant Real Oil Price ($27/barrel) (net present values in millions of US$ 1985)

	EMV	Tax Take
Mackenzie Delta (Onshore)[a]	10.2	65.2%
Beaufort Sea[b]	201.3	49.9%
Atlantic Ocean[a]	42.9	48.0%

Source: Tables 6.22, 6.23, and 6.25 (Chapter 6 above).

Notes:
a. Assumes $70 million exploration program.
b. Assumes $210 million exploration program; negative EMVs prevalent at $70 million program.

Even if oil prices recover sufficiently to make the collapsed-price case obsolete, Kemp's work still suggests that the Canada Lands fiscal system needs further fine-tuning, especially in the case of onshore areas (Mackenzie Delta) where the regime inhibits the finding and development of leaner prospects.

Conclusions

Oil investors' perceptions of the relative attraction of different regions in the world depend first of all on prospectivity, the chance that exploration will lead to discoveries. There is little governing authorities can do about this "tribute of nature." But they do control the government take from successful ventures, a crucial determinant of the after-tax returns which motivate investors.

With regard to fiscal competition between jurisdictions, Kemp's analysis shows that Canada has little to fear. Foreign fiscal regimes are generally more onerous and less flexible than those in Canada – for example, see results in Chapter 6 for Norway, Indonesia, Malaysia, Egypt, and China. If low prices persist, the onus will be on many jurisdictions to restructure their fiscal regimes to retain investor interest. In fact, several countries (Egypt, Norway, Nigeria) have already decided to review their systems to avoid discouraging the development of poorer prospects. In terms of ability to cope with changing economic factors, perhaps the regime that offers the closest approximation to Canada's is Texas. Yet here fundamental differences in prospectivity remain paramount.

What of the nature of the Canadian regimes? Alberta's system is quite regressive for poor prospects, and the relatively favourable results for more likely prospects seem to have a lot more to do with inclusion of special allowances and reliefs rather than with inherent design superiority. If the fiscal system is to rely less on adjustments and more on inherent rules, then royalties should be redesigned to better reflect costs and to retain increasing (decreasing) shares of higher (lower) profits.

The Canada Lands system reveals some design problems in the way it can deter investment in leaner prospects on shore. However, the manifest problems with "collapsed" oil prices have less to do with the fiscal system itself and more to do with basic economics: mid-1987 price levels render high-cost "frontier" resources fundamentally uneconomic. The issue here is not one of further meddling with the fiscal system but one of whether subsidies, outright or otherwise, are warranted.

What has been learnt over the years about the development of Canadian fiscal systems? The need to adjust existing regimes to avoid severe government takes as costs increase and prices fall or fluctuate is well appreciated. Yet in Alberta's case this seems to have taken the form of special allowances, credits, and shifts in royalty schedules rather than the introduction of more robust systems which can better identify resource profitability, on which taxes and royalties should be levied. It may be that attempts to devise such a system will founder in a morass of complexity, yet there is a case for more attention to be given to royalties of the net value type, analogous to the Australian RRT.

Perhaps such royalty systems are too cumbersome to administer over the wide range of Alberta reservoir conditions, but a combination of relatively simple cost-imputation techniques and powerful data processing offers a feasible solution. If so, since the most recent Canada Lands system can be characterized as a flirtation with an RRT-type scheme, structural compatibility between federal and provincial fiscal regimes would be achieved. Consistency can often be a "paste jewel," but here it is a worthy goal.

Tax reform now proposed in Canada seeks lower rates of corporation tax and the elimination of special deductions. This will accentuate the rent-collection role of royalties and the consequent need for them to be sensitive to profits, as fiscal systems grapple with unstable prices.

Notes

1. For discussion of these various measures, see J. Helliwell and T. Heaps, "The Taxation of Natural Resources," Resources Paper No. 95, University of British Columbia (1984).

2. Canadian Petroleum Association, *Statistical Handbook*, 1985. This includes geological and geophysical expenditures. A figure of 47 per cent also applies over the entire postwar period, 1947 to 1985. The 1975-1985 interval includes a period when exploration may have been depressed by pricing regulation and governmental disputes and when it may have been stimulated by cost subsidies (PIP grants).

3. At a sufficiently high level of aggregation – say an entire geological play – the problem of allocating finding costs recedes.

4. It has been suggested that in theory an optimally efficient tax system would consist of a 100 per cent pure rent tax plus differential excise taxes. See M.J. Boskin and M.S. Robinson,

"Energy Taxes and Optimal Tax Theory," *The Energy Journal* 6 (Special Tax Issue, 1985).

5. Calculated from Alberta results (see Figures 6.52 and 6.53).

6. In this vein, see the argument for uniform after-tax returns across reservoir sizes by T.R. Stauffer and J.C. Gault, "Exploration Risks and Mineral Taxation: How Fiscal Regimes Affect Exploration Incentives," *The Energy Journal* 6 (Special Tax Issue, 1985).

7. G. Fane and B. Smith, "Resource Rent Tax" (mimeo., 1986).

8. Royalty elasticities indicate the Alberta royalty formula is not well calibrated with resource "quality" or price; see G.C. Watkins and B. Scarfe, "Canadian Oil and Gas Taxation," *The Energy Journal* 6 (Special Tax Issue, 1985), pp. 28-29, and P. Bradley and G.C. Watkins, "Net Value Royalties: Practical Tool or Economist's Illusion?," paper presented at the Eighth Annual North American Conference of the International Association of Energy Economists, Cambridge, Massachusetts, November 19-21, 1986. For the extensive menu of royalty reliefs, tax credits, and adjustments that determine eventual profitability, see Chapter 3.

9. DataMetrics Limited, "The Oil and Gas Investment Climate: Changes Over a Decade," Canadian Energy Research Institute, Study No. 20, June 1984.

10. Industry *revenue* estimates suggest that the federal government's share of revenue rose between the October 1980 NEP and the fall 1981 agreement, while that of provincial governments fell; see estimates based on work by John Helliwell *et al.*, quoted in G.C. Watkins, "The National Energy Program or Pogrom?," paper presented to the Canadian Society of Exploration Geophysicists and Canadian Society of Petroleum Geologists Convention, Calgary, Alberta, 1984, Table 5.

11. For more discussion, see Watkins, "The National Energy Program or Pogrom?" Section III.

12. Numbers taken from medium-cost case, Figures 6.57, 6.61 (20% PIP), and 6.64 (division of share between respective governments not available).

13. If EMVs for different tax regimes are the same, it does not follow they are equally desirable, since differing tax structures could affect the variance of the EMVs; for an illustration, see Stauffer and Gault, "Exploration Risks and Mineral Taxation: How Fiscal Regimes Affect Exploration Incentives."

14. The collapsed oil price projection used translates into the equivalent of a constant price at Edmonton of some CAN$25 per barrel – about the same as prices at the time of writing (June 1987).

15. See Tables 6.19 and 6.20 (Chapter 6 above) for post-tax EMVs with discovery rate of 1 in 10, 10 per cent discount rate, and collapsed oil price.

List of Abbreviations

AAPG	Association of American Petroleum Geologists
ACRS	Accelerated Cost Recovery System
API	American Petroleum Institute
APRT	Advance Petroleum Revenue Tax
BNOC	British National Oil Corporation
CDE	Canadian Development Expenses
CEDIP	Canadian Exploration and Development Incentive Program
CEDOE	Canadian Exploration and Development Overhead Expenses
CEE	Canadian Exploration Expenses
CNOOC	Chinese National Offshore Oil Corporation
COSC	Canadian Ownership Special Charge

CPE	Centrally Planned Economy
DMP	Domestic Market Price
EGPC	Egyptian General Petroleum Company
EMV	Expected Monetary Value
ETC	Exploration Tax Credit
GNP	Gross National Product
HC	High Cost
HV	High Volume
IORT	Incremental Oil Revenue Tax
ITC	Investment Tax Credit
IVLV	International Very Low Volume
LC	Low Cost
LLV	Low Low Volume
LV	Low Volume
MC	Medium Cost
mcf	Thousand cubic feet
mmcf	Million cubic feet
MOD	Money-of-the-Day
MV	Medium Volume
NEP	National Energy Program
NGGLT	Natural Gas and Gas Liquids Tax
NNPC	Nigerian National Petroleum Company

NORP	**"New" Oil Reference Price**
NPV	**Net Present Value**
OCS	**Outer Continental Shelf**
OPEC	**Organization of Petroleum Exporting Countries**
PCC	**Petroleum Compensation Charge**
PGRT	**Petroleum and Gas Revenue Tax**
PIP	**Petroleum Incentive Program**
PIR	**Progressive Incremental Royalty**
PRT	**Petroleum Revenue Tax**
RRR	**Resource Rent Royalty**
RRT	**Resource Rent Tax**
SPD	**Supplementary Petroleum Duty**
VHC	**Very High Cost**
VHV	**Very High Volume**
VLV	**Very Low Volume**
VVHV	**Very Very High Volume**

Units of Measurement and Conversion Factors

1 cubic metre = 6.2890 barrels

1 kilolitre = 6.2898 barrels

1 long ton = 1.01605 metric tons

1 metric ton = 7.3 to 7.5 barrels (depending on gravity of oil)

20,000 barrels per day ~ 1 million metric tons per year

Glossary of Certain Terms

Netback Pricing: A method of determining the value of crude oil by subtracting from the refined value of a barrel of crude oil the processing costs and profit margin, miscellaneous handling costs, and transport costs from the point of loading of the crude oil.

Resources Generated (from the exploitation of a field): Gross field revenues minus all development and operating costs.

Sum of the Digits Method of Depreciation: A method of depreciation whereby the annual charge decreases by a constant absolute amount each year over the asset's life.

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Petroleum Rent Collection around the World

by Alexander Kemp
with Postscript by Campbell Watkins

This study applies financial models to compare the collection of economic rent in selected oil-producing jurisdictions around the world. In every case the quantitative analysis measures the magnitude and share of the potential rent that accrues to the national (and provincial or state) governments over a range of different exploitation cost conditions, oil prices, field sizes and discount rates. Evaluations are made of the extent to which the fiscal systems "automatically" respond to changes in economic circumstances and are "efficient" for rent collection purposes.

The study examines 13 jurisdictions: Australia, Alaska, China (offshore), Egypt, Indonesia, Malaysia, Nigeria, Norway, Texas, the United Kingdom, the United States Outer Continental Shelf and, for Canada, Alberta and the Canada Lands (prior to the National Energy Program, under the NEP, and post-NEP).

The author is Alexander Kemp, Professor of Economics at the University of Aberdeen, Scotland, a noted authority on the economics of oil field plays. A postscript on the Canadian policy implications is included, written by Campbell Watkins, President of the consulting firm DataMetrics, Calgary, and Adjunct Professor of Economics at the University of Calgary.

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